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The catalog was developed to aid in defining the environmental impacts of U.S. industrial activity. Entries for each industry are in consistent format and form separate chapters of the catalog. The petroleum refining industry is involved primarily in the conversion of crude oil into more than 2500 products including liquefied petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, a variety of fuel oils, lubricating oils, and feedstocks for the petrochemical industry. The industry is discussed in five segments: crude separation, light hydrocarbon processing, middle distillate processing, residual hydrocarbon processing, and auxiliary processes. Four process flow sheets and 32 process descriptions characterize the industry. For each process description, available data is presented on input materials, operating parameters, utility requirements, and waste streams. Related information, provided as appendices, includes company, product, and feedstock data.

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INDUSTRIAL PROCESS PROFILES FOR ENVIRONMENTAL USE:

CHAPTER 3. PETROLEUM REFINING INDUSTRY

by

J.C. Dickerman, T.D. Raye, J.D. Colley, and R.H. Parsons

Radian Corporation
P.O. Box 9948
Austin, Texas 78766

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PETROLEUM REFINING INDUSTRY

INDUSTRY DESCRIPTION

The petroleum refining industry is involved primarily in the conversion of crude oil into more than 2500 products including liquefied petroleum gas, gasoline, kerosene, aviation fuel, diesel fuel, a variety of fuel oils, lubricating oils, and feedstocks for the petrochemical industry. By definition, petroleum refinery activities start with crude oil storage and terminate with storage of the refined products. Production of gas and oil and transportation and distribution of the products are normally considered part of other industries.

Crude oil is the major raw material processed in a refinery. Data published in the 5 April 1976 Oil and Gas Journal indicated that as of 1 January, 1976 the processing capacity of the United States petroleum refining industry was over 2.26 million cubic meters per day. The chemical composition of crude oil varies widely depending on its source. It is largely a mixture of paraffinic, naphthenic, and aromatic hydrocarbons plus small amounts of sulfur, nitrogen, oxygen, and various metals. The chemical composition of the crude oil being processed will determine, in part, the product slate from a particular refinery. For example, a paraffinic crude will tend to produce better lube oil stocks than will a naphthenic crude and is thus the favored feedstock for that product.

The refining industry has been divided into four operations involving different types of processes. These are (1) Crude Separation, (2) Light Hydrocarbon Processing, (3) Middle and Heavy Distillate Processing, and (4) Residual Hydrocarbon Processing. Detailed discussions of each operation and its component processes including flow diagrams are presented in a later section. Auxiliary processes were not included on the process flow sheets but are discussed as a separate segment.

Some of the processes involved in the manufacture of refinery products are distillation, absorption, extraction, thermal and catalytic cracking, isomerization and polymerization. Flow diagrams have been prepared which illustrate the sequence in which these processes interact to produce refinery products. Few, if any, refineries employ all of these processes. Some of the processes are representative of a limited size range of refineries and are designed for a particular crude oil.

Larger refineries do, however, use most of these processes. American refineries typically use more processes than foreign refineries, as they are generally designed to maximize motor gasoline production. European refineries generally maximize production of heating fuels. Complex American refineries generally produce a minimum of residual oil. Fuel oil for the U.S. East Coast is produced predominately in Caribbean refineries which have minimum facilities for motor gasoline production.

TABLE 1. CRUDE CAPACITY OF U.S. REFINERIES

YEAR*	CAPACITY PER CALENDAR DAY	
	hm^3	Thousands of Barrels
1967	1.662	10452
1968	1.771	11142
1969	1.832	11523
1970	1.932	12155
1971	2.016	12681
1972	2.081	13087
1973	2.128	13383
1974	2.260	14216
1975	2.360	14845
1976	2.397	15075

* as of January 1 of the year indicated

Source: Oil and Gas Journal, Annual Refining Issues

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of natural gas liquids were consumed. Natural gas liquids are condensed light hydrocarbons (C_4-C_8) which come directly from the producing well. Many other materials are used by this industry in much smaller quantities. Examples are alkyl lead for gasoline production; additives for lube oil production, such as detergents, viscosity index improvers, and anti-oxidants; barium compounds for diesel fuels; and caustic, sulfuric acid, amines, hydrofluoric acid, and clay.

It has been reported that over 3,000 different chemical compounds may be present in crude petroleum. Petroleum is a mixture of paraffinic, naphthenic, and aromatic hydrocarbons containing varying amounts of sulfur, nitrogen, and oxygen along with a small amount of ash which contains inorganic materials. While it is difficult to describe a "typical" crude due to its chemical diversity, ranges for elemental composition and physical properties can be determined and are presented in Table 2. Detailed crude oil compositions are shown in Appendix A.

Some of the inorganic materials contained in the ash such as iron, nickel, and vanadium act as a poison to catalysts. As the metal accumulates on the catalyst, the activity of the catalyst decreases. Crudes with high metal concentrations require more frequent catalyst regeneration resulting in more frequent atmospheric emissions from this source.

Sulfur in the crude is the source of all sulfur dioxide emissions from a refinery. Emissions of sulfur dioxide result from firing sulfur bearing fuels (derived from the crude) in the plant boilers and furnaces and from incineration of the tail gas from the sulfur recovery plant. The trend toward a greater use of high sulfur imported crude increases the sulfur dioxide emissions problem. Sulfur may be present as free sulfur, hydrogen sulfide, or in organic compounds such as thiophenes, mercaptans, and alkyl sulfudes. Mercaptans produce a strong odor and are often oxidized to disulfides to reduce the odor when sulfur removal is not practiced. Sulfur also increases the corrosive characteristics of both the crude and its products.

Products

Approximately 2500 products are produced wholly or in part from petroleum. Most of these products are blends of several refinery streams. In 1973 the U.S. demand for refined products was a record 2.7 million cubic meters per day. Although the components can vary widely, refinery products can be classified into one of several categories: fuels, lube oils, and so forth. Table 3 lists the major petroleum products and their production in 1973. Properties and characteristics of the major petroleum products are shown in Appendix B.

Refinery products vary widely with location, climate, and season. For example, winter brings a higher demand for heating fuel oils. Also winter gasoline must contain a higher percentage of volatile products to enhance cold weather starts. Summer weather requires a reduction in the volatile components to decrease the

Table 2. PROPERTIES OF CRUDE OIL

Elemental Composition	Range (%)
Carbon	83-87
Hydrogen	11-14
Sulfur	0-5
Nitrogen	0-0.88
Oxygen	0-2
Ash*:	.01-.05

Iron
Calcium
Magnesium
Silicon
Aluminum
Vanadium
Nickel
Copper
Manganese
Strontium
Barium
Boron
Cobalt
Zinc
Molydenum
Lead
Tin
Sodium
Potassium
Phosphorous
Lithium

Physical Properties	°API
Specific Gravity	12-49

Typical Yields, TBP Distillation	Volume %
C4 & Lighter, < 15.6°C	0-3
LSR Gasoline & Naphtha, 15.6-193°C	25-45
Kerosene, 193-288°C	10-25
Light Gas Oil, 288-343°C	5-15
Heavy Gas Oils, 343-538°C	20-30
Residuum, 538°C +	5-25

---

* Elements in the ash are presented in decreasing concentrations.

Table 3. MAJOR PETROLEUM PRODUCTS, 1973

Product	Production m^3/day	Percent of Total Products
Gasoline	1,068,000	39
Distillate Fuel Oil	490,000	18
Residual Fuel Oil	444,000	16
Liquefied Gases	178,000	7
Jet Fuel	167,000	6
Asphalt	79,500	3
Still Gas for Fuel	77,000	3
Ethane (includes ethylene)	52,000	2
Petrochemical Feedstocks	57,100	2
Coke	41,500	1
Kerosene	34,300	1
Lubricants	25,800	0.9
Special Naphthas	14,200	0.5
Waxes	3,000	0.1
Road Oil	3,500	0.1
Miscellaneous Products	8,300	0.4
	2,743,200	100.0

likelihood of carburetor vapor lock and minimize vaporization losses. Refineries must be sufficiently flexible to meet these varying demands.

As the size of a refinery increases, the number of products increases, and the processing operation becomes more flexible. The production rate of each of the products can be varied significantly by making relatively minor changes in refinery processing conditions. Hydrocarbon fractions can be shifted from one product to another to meet product demands.

Gasoline is by far the major product of this industry. Its production rate is nearly one-half of the total industry output, and its value is more than one-half of the value of all products sold. Finished gasoline is a blend of products from several refinery processes including straight run and cracked gasolines, reformed naphthas, alkylates, isomerates and butanes. Gasoline also includes several minor additives such as alkyl leads, dyes, antioxidants and detergents, usually purchased from other industries. The high octane rating necessary for good engine performance is obtained from aromatic hydrocarbons and branched-chain paraffinic and naphthenic compounds. Butane and isopentane have high octane ratings, but the amount of these compounds in gasoline is limited by their high volatility. No-lead and low-lead gasoline production requires an increased use of aromatic hydrocarbons to obtain high octane fuels. The environmental effects of combustion of high aromatic fuels have not been fully defined.

Light diesel oils distill in the 188-315°C range and can have a wide range of specifications. Their performance is described by a cetane rating that refers to the ignition characteristics of the oil in a diesel motor. Fuels with a good cetane rating are used for diesel fuel, while those with a poor rating are used to produce burner fuel.

Distillate fuels have boiling ranges similar to diesel oils. Any oil that can be distilled either in the crude still or in the vacuum still and oils of similar boiling ranges from various refinery processes are used as fuel oil. Generally, some of the oil is treated to remove sulfur. Distillate fuel is widely used for domestic heating.

Residual oils are the bottoms product from atmospheric or vacuum distillation. They frequently contain high concentrations of potential pollutants. While it is not current practice to desulfurize residuals in the U.S., some commercial processes are available and in operation. Some residual oils are blended with kerosene or light gas oils to reduce viscosity and sulfur concentration and used as boiler fuel in steam and electric power generation facilities (No. 5, No. 6, Bunker C fuel oil).

Other residuals are charged to coking, visbreaking, or asphalt processes. Coking converts residuals into naphthas and gas oils for further processing. The petroleum coke residue of this process is used in metallurgical processes, if it is low sulfur, or as a fuel. Visbreaking improves viscosity without significantly altering the boiling range. Asphaltic base crude oil residuals are processed to recove the asphalts which are used with rock (aggregate) as a cement in road pavement, for manufacture of roofing materials, and for other applications.

Liquefied petroleum gas (LPG) is a mixture of C_2, C_3, and C_4 hydrocarbons. It is widely used for industrial heating and for domestic heating and cooking where natural gas is unavailable or scarce. Natural gas companies frequently add LPG to natural gas at times of peak demand. LPG is an excellent motor fuel with a high octane rating and minimum air pollutant emissions. It is occasionally used for truck or bus fleets. LPG is quite widely used for fork lifts, payloaders, and other applications inside buildings where low engine emissions are important. Sometimes the designation LPG is restricted to a product of the natural gas industry. When that restriction is made, the same material made by the petroleum industry is referred to as liquefied refinery gas (LRG).

Petrochemical feedstocks supplied by refineries include olefins, LPG, and aromatic compounds. In addition, naphtha is cracked in a thermal cracking process to produce ethylene. Ethylene production is performed in both refineries and petrochemical plants. Petrochemical feedstocks account for only a small percentage of the refining industry's production; only about two percent of production in 1973 was petrochemical feedstocks.

Jet aircraft fuels are of two basic types: a kerosene type which boils in the 188-260°C range and a naphtha type boiling in the 121-260°C range. Special quality control measures are required for jet fuels as engine failure could be catastrophic. Wax removal is required to reduce the freezing point and aromatic removal is employed to reduce smoking.

Kerosene is a petroleum fraction which boils in the 177-288°C range. It was one of the first petroleum fractions to be produced and was used as lamp oil. Various chemical sweetening processes were developed to remove mercaptans from kerosenes to reduce odor problems. Kerosene is used today only in small-scale applications such as domestic cooking.

Companies

As of 1 January 1974 there were 142 companies which comprised the U.S. petroleum refining industry. These companies operated 247 refineries in 39 states. Table 4 lists the 10 largest refiners and the production capacity of each along with the combined capacity of the other 169 refineries. A complete listing by company of the production capacities of all 247 refineries is found in Appendix C.

Many of these companies are also involved in related industries such as the petrochemicals industry which uses refinery products as feedstocks. Petrochemical plants often border refineries to permit an easy exchange of products. These plants often generate by-product materials similar to refinery intermediate products which are then sold to the refinery.

As is shown in Appendix C, many refineries have crude capacities of less than 800 cubic meters per day (5,000 barrels per day). Operation of these small refineries is generally economically favored only by production of specialty items, lube oils, or asphalts.

TABLE 4. CAPACITIES OF THE TEN LARGEST REFINERS

Company	Number of Refineries	Crude Capacity m^3/day
Exxon	5	199,068
Shell	8	176,331
Texaco	12	172,197
Amoco	10	169,335
Standard Oil of California	12	156,456
Mobil	8	148,188
Gulf	8	136,835
ARCO	6	125,578
Union Oil	4	77,433
Sun Oil	5	76,956
All Others	169	824,448
TOTAL	247	2,262,825

Environmental Impact

The petroleum refining industry produces gaseous, solid, and liquid pollutants. Air emissions are by far the largest emission problem of the industry. The major air pollutants emitted are particulates, hydrocarbons, carbon monoxide, sulfur oxides, and nitrogen oxides.

There are very few process units which directly emit gases to the atmosphere. The major refining process units which do emit gases directly to the atmosphere are the catalytic cracking units, the sulfur recovery processes, and storage tanks. Many processes employ heaters which contribute combustion emissions directly to the atmosphere. Virtually all of the refinery's NO_x emissions result from process heaters. Particulate and SO_x emissions from these heaters are dependent upon the chemical composition of the fuel and are generally low.

Fugitive emissions are another source of atmospheric pollutants. These sources include pump seals, valves, relief vents, and leaks in vessels and pipe walls. It is difficult to quantify these emissions as they do not occur at one particular source or location. Potential fugitive emissions could occur from the thousands of valves, seals, pumps, etc., found throughout the refinery. Attempts have been made, however, to estimate the extent of these emissions. These estimates indicate that fugitive emissions are the largest source of air pollution from a refinery.

Table 5 is presented to provide a listing of the main process contributors of each atmospheric pollutant. These processes are described individually in later sections. Table 6 presents a summary of the estimated atmospheric emissions produces by the refining industry along with an estimate of U.S. emissions for comparison.

The major sources of liquid effluents are oil and grease in condensed steam from various processes, cooling water from various processes, tank cleaning wastes, spent chemicals, waste caustics containing cresylic acids and sulfides from gas treating, lead wastes from doctor treating and product storage, and oil spills. The technology of treating refinery water streams is well established. Basic water cleanup processes commonly found in refineries are oil water separators, sour water strippers, sedimentation for suspended solids, acid base neutralization, and biological oxidation. The objective of several recently completed or in-progress studies is the characterization of aqueous wastes from individual or combined process streams. The effluents from activated carbon and activated sludge water treatment processes, API separators, and stripping units are among the liquid wastes being studied. State-of-the-art investigations for the refinery industry have also been prepared. Analytical methods are being developed under separate studies. Although many compounds are present in the liquid effluent from a particular process, they are generally either eliminated or reduced to an acceptable level before the water is discharged from the refinery.

A petroleum refinery generates a wide variety of solid wastes. Catalyst fines from cracking units; coke fines; iron sulfide; clay filtering media; and sludges from tank cleaning operations, oil-water separators, and biological oxidation processes are typical solid wastes. These wastes are generally landfilled or incinerated. Spent catalysts that are not worth processing for recovery of valuable components are an intermittent solid waste stream. Typical components of waste catalysts include aluminum, cobalt, nickel, and titanium compounds. Spent catalysts are generally landfilled. Construction activity also generates a large volume of solid wastes. The Office of Solid Waste Management Programs is currently sponsoring an investigation of the wastes and disposal methods for this industry; these results will be available in the near future.

The refining industry is also a potential emitter of some hazardous compounds. Studies are currently underway which attempt to define an approach for analyzing the hazardous compounds emitted from refineries. A list of several hazardous compounds along with their potential emission sources is presented in Appendix D.

Table 5. POTENTIAL SOURCES OF ATMOSPHERIC EMISSIONS WITHIN REFINERIES

Type of Emission	Source
Particulates	Catalytic Cracker, Fluid Coking, Catalyst Regeneration, Process Heaters, Boilers, Decoking Operations, Incinerators
Sulfur Oxides	Sulfur Recovery Unit, Catalytic Cracking, Process Heaters, Boilers, Decoking Operations, Unit Regenerations, Treating Units, Flares
Nitrogen Oxides	Process Heaters, Boilers, Catalyst Regeneration, Flares
Hydrocarbons	Storage Tanks, Loading Operations, Water Treating, Catalyst Regeneration, Barometric Condensors, Process Heaters, Boilers, Pumps, Valves, Blind Changing, Cooling Towers, Vacuum Jets
Carbon Monoxide	Catalyst Regeneration, Decoking, Compressor Engines, Incinerators
Odors	Treating Units, Drains, Tank Vents, Barometric Condensers, Sumps, Oil Water Separators

TABLE 6. COMPARISON OF EMISSIONS FROM PETROLEUM REFINING WITH TOTAL U.S. INDUSTRIAL POINT SOURCE EMISSIONS FOR SELECTED POLLUTANTS DURING 1972

	Total Industrial Process Point Source Emissions Gg/yr	Total Emissions From the Petroleum Refining Industry[a] Gg/yr
Particulate	8413	81.6[b]
SO_x	6132	2015
CO	15862	1950
HC	5858	1873

a 1972 average crude run: 1,860,000 m^3/day (11,696,000 bbl/day).
b based on particulate emission control factor of 60 per cent.

Compiled from data contained in:

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INDUSTRY ANALYSIS

Data for the industry analyses are presented in five sections. The order of presentation is (1) Crude Separation, (2) Light Hydrocarbon Processing, (3) Middle and Heavy Distillate Processing, (4) Residual Processing, and (5) Auxiliary Units.

Each of the five segments is divided into component process modules, and each module is described in detail. The Crude Separation segment describes crude oil handling and distillation processes which split the crude into three broad fractions: light hydrocarbons, middle and heavy distillates and residual oils. Light hydrocarbons are defined for this report as naphtha boiling range and lighter fractions. Residual oils are defined as crude distillation bottoms or residue. Middle and heavy distillates are the fractions boiling between the naphtha range and the residuals. These distillates include kerosenes, gas oils and lube stocks. Auxiliary units are described in a separate segment for convenience and clarity of presentation.

The first four areas discussed above are depicted graphically in Figures 1 through 4 with module inter-relationships schematically presented. Each figure immediately follows its respective industry segment description. Each process within a particular segment is discussed in the section immediately following the figure on which it is shown. The various processes within a refinery have been numbered consecutively from 1 to 32. The numbers assigned to the modules on the process flow sheets correspond to the process numbers given the module descriptions.

Within each module description, data have been presented on operating variables, utility requirements, and associated waste streams. In most cases a range of data is given rather than a precise figure, since variables depend on product split desired, chemical composition of crude feedstock, product purity requirements, and several other factors. Therefore, ranges of data more nearly describe the industry as a whole. The data are considered reliable and accurate.

Crude Separation

Crude separation is a term used to describe those processes which directly and indirectly separate crude oil into a variety of intermediate products. These intermediate products are used as feedstocks for downstream refinery processing units. There are eight process modules included in crude separation. Of these eight modules, four are directly involved with crude oil processing and four process crude oil indirectly. These modules are shown schematically in Figure 1.

The four modules which process crude oil directly are crude storage, desalting, atmospheric distillation, and vacuum distillation. These processes contribute significantly to both air and water emissions from a refinery.

The four modules which process crude indirectly are H_2S removal, sulfur recovery, gas processing, and hydrogen production. Of these, only the sulfur recovery process produces a significant emission stream. Its off gases are considered to be the largest sulfur air emission source in a refinery. The other three processes contribute air emissions only through process heaters and fugitive leaks. Water emissions from these processes are not considered significant.

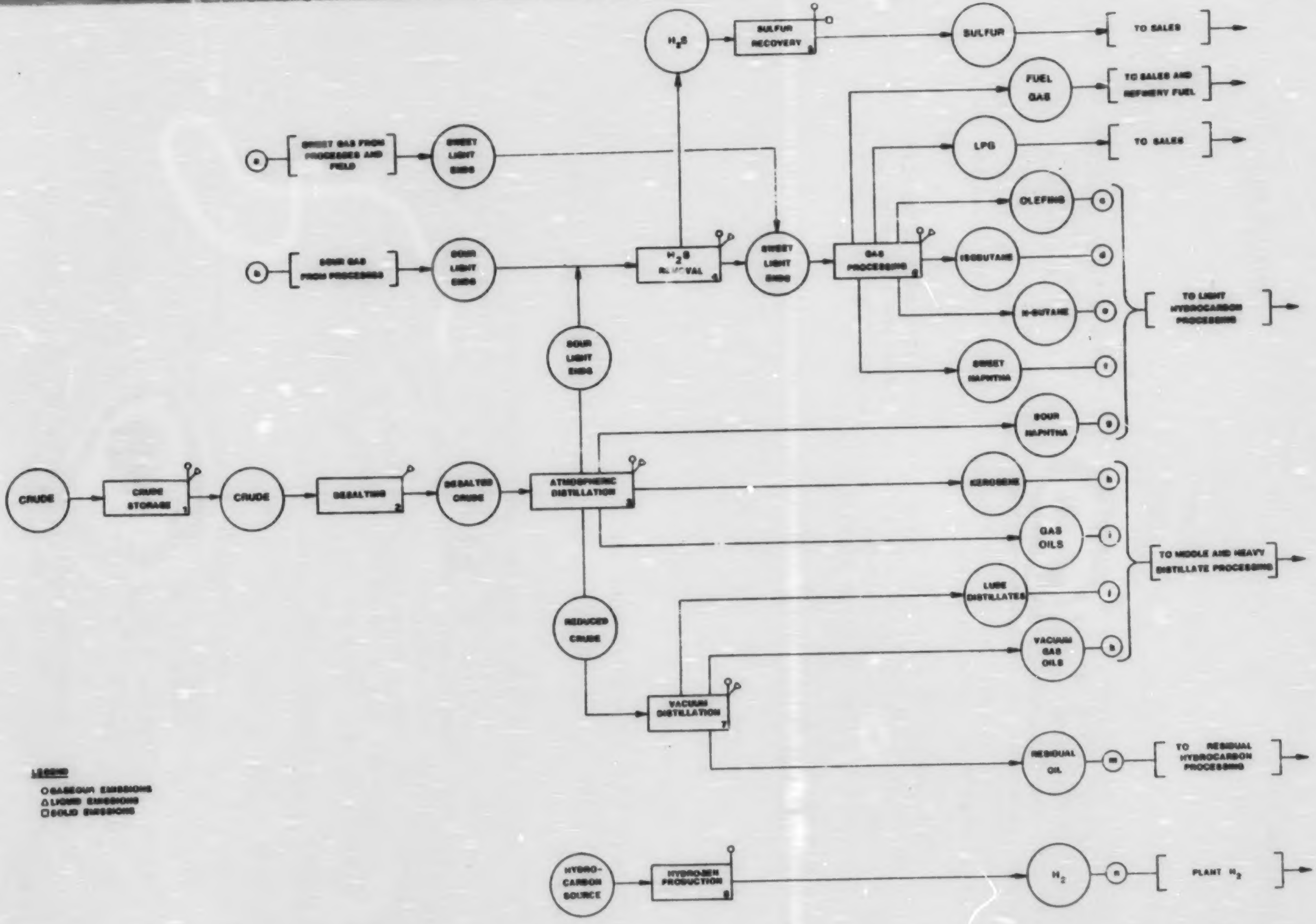

a
SWEET GAS FROM PROCESSES AND FIELD
SWEET LIGHT ENDS
b
SOUR GAS FROM PROCESSES
SOUR LIGHT ENDS
H_2S
SULFUR RECOVERY
9
SULFUR
TO SALES
H_2S REMOVAL
5
SWEET LIGHT ENDS
GAS PROCESSING
6
FUEL GAS
TO SALES AND REFINERY FUEL
LPG
TO SALES
OLEFINS
c
ISOBUTANE
d
N-BUTANE
e
SWEET NAPHTHA
f
SOUR NAPHTHA
g
TO LIGHT HYDROCARBON PROCESSING
SOUR LIGHT ENDS
CRUDE
CRUDE STORAGE
1
CRUDE
DESALTING
2
DESALTED CRUDE
ATMOSPHERIC DISTILLATION
3
KEROSENE
h
GAS OILS
i
LUBE DISTILLATES
j
VACUUM GAS OILS
k
TO MIDDLE AND HEAVY DISTILLATE PROCESSING
REDUCED CRUDE
VACUUM DISTILLATION
7
RESIDUAL OIL
m
TO RESIDUAL HYDROCARBON PROCESSING
HYDRO-CARBON SOURCE
HYDROGEN PRODUCTION
8
H_2
n
PLANT H_2
LEGEND
○ GASEOUS EMISSIONS
△ LIQUID EMISSIONS
□ SOLID EMISSIONS

FIGURE 1. REFINERY CRUDE SEPARATION

Crude Storage

1. Function - The purpose of crude storage is to provide a surge capacity and reservoir during periods when crude deliveries may be irregular. Storage is also used for segregation of varying quality crudes since different quality crudes undergo different processing steps. Typical storage capacities are between a two-week and a two-month supply of crude oil. The storage tanks also provide a residence time to allow water to settle out from the crude.

   Crude oil is generally stored in large cone roof tanks with capacities up to 40,000 m^3 (250,000 bbl). Floating roof tanks are now being used for storage of light volatile crudes. From storage, the oil is sent to the desalters and then to crude distillation.

2. Input Materials - Raw crude oil from production wells is the feed to crude storage operations.

3. Operating Parameters -

   Temperature: Ambient

   Pressure: Atmospheric

4. Utilities - Utility requirements are low.

   All electricity is used in pumping the crude to and from the storage tanks.

5. Waste Streams - Both liquid and atmospheric emissions result from crude storage. Liquid effluents consist of about 12 liters water per cubic meter of stored crude and contain dissolved salts. Atmospheric emissions result from evaporative hydrocarbon losses associated with pumping the crude into and out of the tanks. These emissions consist predominantly of light hydrocarbons. Estimates of working losses are 0.88 kg hydrocarbon per 10^3 liter throughput, and breathing losses are estimated to be 0.02 kg per 10^3 liter storage capacity.

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

(3) Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd Ed., AP-42, Research Triangle Park, N.C., 1973

CRUDE SEPARATION

PROCESS NO. 2

Desalting

1. Function - The desalting unit is generally the first processing unit in a crude oil refining scheme. This process is used to remove salt, water, and water soluble compounds from the crude, as these compounds can eventually result in equipment fouling, corrosion, or possible catalyst poisoning in downstream processing units.

   Water is added to the incoming raw crude and thoroughly mixed. The wet crude is then heated to break emulsions and the water and dissolved impurities are separated. Separation is accomplished by physical decanting and electrostatic coalescing. The separated water is collected and sent to the waste water treating system, and the desalted crude is preheated and sent to the atmospheric distillation column.

2. Input Materials - The feed to the desalting unit is crude oil from storage.

3. Operating Parameters -

   Temperature: 38-155°C (100-300°F)

   Pressure: 2.8+ kg/sq cm (40+ psi)

4. Utilities -

   Thermal Energy: 34,800 kcal per m^3 of crude charge (22,000 Btu/bbl) may be obtained by heat exchange with a hot stream from the distillation column or by process heaters

   Electricity: .063 kWh/m^3 - used to run pumps and the coalescer

   Process Water: 35-60 liters per m^3 of crude charged (1.5-2.5 gal/bbl)

   Waste Streams - A liquid effluent composed of the feed water inlet plus the salts picked up by the water is released from this unit. Water to the unit is usually fresh water plus sour water from other units. The effluent rate is about 47 liters per m^3 of oil processed. The largest waste water contaminants are dissolved solids (average concentration 3700 ppm) which are composed largely of chlorides, sulfates, and bicarbonates. Oil, phenols, and sulfides are also found, but in lesser concentrations. Average concentrations for these pollutants are 169, 15, and 4 ppm, respectively. Desalter effluent is dumped to the sewer or waste water system.

6. EPA Source Classification Code - None exists.

7. References

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), (1974).

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Atmospheric Distillation

1. Function - Atmospheric distillation involves the physical separation of hydrocarbon components into fractions or intermediates of a specified boiling temperature range by distillation and steam stripping. The major processing equipment items include the heat exchanger preheat train, direct fired furnace, atmospheric fractionator, and side stream product strippers.

Desalted crude is preheated in the heat exchanger train by recovering process heat. The preheated crude is then charged to a direct-fired furnace where additional heat is supplied to achieve partial vaporization of the crude petroleum. Both the liquid and vaporized portions are charged to the atmospheric fractionator at a temperature of about 344 to 371° C (650 to 700° F).

The crude charge is separated into several petroleum fractions within the atmospheric fractionator. A naphtha and lighter stream is taken from the tower overhead where it is condensed, and the non-condensable light ends are treated and/or recovered in other refinery units. Several liquid side-stream fractions are withdrawn from the fractionator at different elevations within the tower. These fractions are charged to the side-stream product strippers where lighter hydrocarbons are stripped from these fractions and returned to the fractionation tower. The stripping medium is either steam, light petroleum gases, or reboiler vapors. In addition to the side-stream strippers, the atmospheric fractionator has a bottoms stripping zone whereby lighter hydrocarbons are steam stripped from the residual product.

The fractions withdrawn from the atmospheric tower are progressively heavier as they are taken at successively lower points from the fractionator. However, the end point of the heaviest side-stream product closely corresponds to the crude's temperature as charged to the fractionator. Fractionator bottoms (topped crude) is the heaviest petroleum fraction and is the charge to the vacuum distillation unit.

The intermediate products are naphtha, kerosene, distillate or diesel oil, gas oil and topped crude. The naphtha is blended into motor fuels or any of several of the refinery products, or further processed to improve octane rating and/or reduce sulfur content. The kerosene may be chemically sweetened or hydrogen treated and sold directly or sent to blending. The distillate or diesel oil may be sold for diesel or fuel oil, hydrogen treated, hydrocracked, catalytically cracked, or blended. The gas oil may be sold as fuel oil, hydrogen treated, hydrocracked, catalytically cracked, or blended. The topped crude is usually the feed to the vacuum distillation process although it may be sold for fuel, blended into fuels, hydrogen treated, or catalytically cracked.

2. Input Materials - Desalted crude is the feedstock to this unit.

3. Operating Parameters - The following conditions are typical of the fractionator:

Pressure: Atmospheric

Temperature: 120°C - at top of fractionator
370°C - at fractionator bottom

These are rather large processing units with capacities up to 39,000 m^3/day (240,000 bpd).

4. Utilities -

Electricity: 2.5 kWh per m^3 charge

Steam: 143 kg per m^3 charge - used for stripping

Heaters: 158,000 kcal per m^3 charge

Cooling Water: 690 liters per m^3 charge

5. Waste Streams - Atmospheric distillation is a closed process with only fugitive air emissions and those associated with the process heaters which will be covered in a later section. A sour water effluent is produced from the condensed stripping stream. The effluent rate is dependent upon the amount of stripping steam employed. The primary contaminants in the foul condensate are sulfides and ammonia (each about 4000 ppm) while phenols and other soluble hydrocarbons may be present in smaller amounts.

6. EPA Source Classification Code - None exists.

7. References -

(1) Hydrocarbon Processing Refining Processes Handbook", *Hydrocarbon Proc.* 53(9), (1974).

(2) Nack, H., et al., *Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities*, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(3) Radian Corporation, *A Program to Investigate Various Factors in Refinery Siting*, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

(4) Watkins, R. N., "How to Design Crude Distillation", *Hydrocarbon Proc.* 48(12), 1969.

H_2S Removal

1. Function - The acid gas removal unit is designed to remove hydrogen sulfide from hydrocarbon gases by absorption in some aqueous, regenerable sorbent. A number of gas treatment processes are available, and they are distinguished primarily by the regenerative sorbent employed. Amine-based sorbents, however, are most commonly used.

   The feed to the unit is contacted with the sorbent, such as diethanolamine, in an absorption column to selectively absorb H_2S from the hydrocarbon gases. Hydrogen sulfide is then removed from the sorbent in a regeneration step. The products are a sweet hydrocarbon gas and a concentrated hydrogen sulfide stream. The sweet gas may either be further processed in light end recovery processes or may be charged as a raw material to other refinery or petrochemical processes. The hydrogen sulfide stream is normally routed to a sulfur plant for recovery of its sulfur content.

2. Input Materials - Sour hydrocarbon gases from various processing units constitute the feed to the acid gas removal unit. Refinery processes which produce substantial quantities of these gases are: crude distillation, hydrodesulfurization, catalytic cracking, thermal cracking and hydrocracking.

   The sorbent used to remove hydrogen sulfide is also a feed to this unit. It is generally regenerable, and make-up rates are usually quite low.

3. Operating Parameters - The following conditions are typical of absorber operations:

   Pressure: 10.5 kg/sq cm

   Temperature: 38°C

4. Utilities -

   Electricity: .022 kWh/kg removed gas

   Steam: 0.8-1.6 kg/kg removed gas

   Cooling Water: 45-82 liters/kg removed gas

5. Waste Streams - No atmospheric emissions, other than fugitive emissions, are produced from this unit. Liquid effluents are produced as spent amine solutions which must be replaced; about 4 liters per 159 m^3 (1 gal/ 1000 bbl) for diethanolamine. Usually, a small quantity of amine solution

is continuously lost from the circulating system by entrainment in the absorber. The lost amine solution is removed from hydrocarbon streams in knockout vessels and becomes part of the liquid effluent. The amount of waste is proportional to the amount of hydrogen sulfide removed from refining streams and, therefore, depends upon the amount of sulfur in the crude and the extent to which the products are desulfurized.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), (1974).

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Sulfur Recovery

1. Function - A sulfur recovery plant converts hydrogen sulfide to elemental sulfur by controlled combustion and reactions occuring in a series of catalytic beds. In the Claus sulfur recovery process, the feed is first combusted with substoichiometric amounts of air to form sulfur and water. The off gas is cooled, and sulfur is condensed as a liquid. About sixty to seventy percent conversion occurs in the furnace.

   The remaining gases are reheated and passed through catalytic reactors. Each reactor has an effluent condenser where the elemental sulfur is recovered. Reheat of reactor effluent is necessary for sulfur recovery in subsequent reactors. The number of reactors varies with the conversion desired and with the H_2S concentration. Fifty to sixty percent of the remaining sulfur is converted in each reactor stage so that two to four reactors are required.

   The unconverted H_2S leaves the process in a tail gas stream and is either further processed or incinerated to remove the last traces of reduced sulfur compounds. The sulfur recovered by this process is sold as a refinery by-product.

2. Input Streams - H_2S from the acid gas removal plant and H_2S from sour water stripper systems comprise the feed to the sulfur plant. The amount of sulfur reaching the sulfur recovery unit varies with sulfur in the crude and the extent of desulfurization. Typically 60% of the sulfur entering with the crude reaches the sulfur recovery plant.

3. Operating Parameters - The following conditions are typical of those found in the reactors:

   Temperature: 245°C

   Pressure: 1-2 Atm

   A bauxite catalyst is most commonly employed for this process.

4. Utilities

   Heater: 2220 kcal/kg sulfur

   Steam: 4 kg/kg sulfur - generated in a waste heat boiler. The steam produced in a sulfur recovery plant can provide 5-30% of the total refinery steam requirements.

5. Waste Streams - The sulfur compounds which are not converted to elemental sulfur in the sulfur recovery plant are possible air contaminants. Possible sulfur emissions are SO_2, H_2S, COS, CS_2, and mercaptans. After incineration all sulfur compounds theoretically

should be converted to SO_2, but in actual practice they are not. Sulfur dioxide concentration in the effluent tail gas is approximately 15,000 ppm. A 15,900 m^3/day (100,000 bpd) refinery with a 1% sulfur crude and a 95% efficient sulfur plant will produce 4500-5400 kg/day (5-6 ton/day) of sulfur emissions.

In recent years, environmental concerns have led to the installation of tail gas cleanup units which further reduce the SO_2 concentration to approximately 500 ppm, thus representing an overall sulfur recovery efficiency of 99.8+%. The above hypothetical refinery with a 99.8% overall sulfur recovery plant would emit 150-180 kg/day (0.17-0.20 ton/day) of sulfur.

There is no wastewater stream since all water formed remains in the vapor state and is exhausted with the flue gases. There are only minor solid wastes associated with disposal of the spent catalyst. Catalysts are generally regenerable and require disposal only infrequently (once every two years).

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Gas Processing

1. Function - The function of gas processing is to recover various hydrocarbons as purity products or as mixtures of specified composition, for use in other refinery processes, as gasoline blending components and for sales. The separations are accomplished by absorption and/or distillation. The recovery processes utilized depend on the products desired. Gas processing units are used to produce fuel gas, methane, ethane, propane, propylene, normal and isobutane, butylene, normal and isopentane, amylene and/or a light naphtha.

2. Inout Materials - Feed to gas processing units is provided by crude distillation, catalytic reforming, catalytic cracking, hydrocracking, thermal cracking and, to a lesser extent, hydrodesulfurization. Many refineries also process natural gas liquids as a separate input stream.

3. Operating Parameters - The operating parameters vary significantly for this process depending upon the products recovered. Temperatures as low as -73°C are required to obtain an ethane cut and high pressures, 25.2 kg/sq cm (360 psi), are used in absorbing propane.

4. Utilities -

   Electricty: 12.5 kWh/m^3 of feed - used for compressing the gases.

5. Waste Streams - Gas processing is a closed process with no air emissions except from process heaters. The possibility of fugitive leaks always exists. Liquid effluents associated with caustic and water scrubbing of product streams are produced. These wastes are treated in neutralization and waste water treating facilities.

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Vacuum Distillation

1. Function - Vacuum distillation separates the atmospheric residue from the crude still into a heavy residual oil and one or more heavy gas oil streams. Vacuum fractionation is employed to avoid the extremely high temperatures that would be necessary to produce these heavy distillates by atmospheric fractionation.

   Vacuum fractionators are maintained at approximately 30-150 mm Hg absolute pressure by either steam ejectors or mechanical vacuum pumps. These vacuum systems are designed to remove non-condensable hydrocarbon vapors, which are produced by thermal cracking of the reduced crude charge heating.

   Vacuum distillation is accomplished in one or, occasionally, two fractionation stages. Reduced crude is heated in a direct-fired furnace and charged to the vacuum fractionator. Product specifications and dispositions will vary with crude type and refinery design. Vacuum distillation plus stream stripping is used to produce narrow boiling range lube oil stocks for further processing. Steam stripping is not required in the fractionation of vacuum distillates for catalytic cracking or visbreaking feedstocks.

   The intermediate product from the vacuum distillation process may be used for several purposes. Its ultimate use will be determined by the crude feedstocks and the subject refinery design. In some cases it may be sent to the asphalt plant; a different crude feed might dictate that the intermediate product be sent to a coker to be thermally cracked into a gasoline feedstock. Still other possible routings of the intermediate product are to send it to a visbreaker for cracking into a distillate fuel or to send it to a hydrotreater to remove sulfur for further upgrading. The choice of these options may be limited by the crude characteritstics and/or the existing refinery design.

   With suitable feedstocks, the residuals from vacuum distillation may be sent to the lube oil plant either directly or through a hydrogen treating process. Other distillates are treated similarly to the gas oil stream from the crude still and catalytically hydrocracked, catalytically cracked, or used as fuel oil.

2. Input Materials - Feed to this unit is topped crude from the atmospheric still.

3. Operating Parameters - Typical vacuum column operating conditions are:

Pressure: 30-150 mm Hg absolute

Temperature: 400°C

4. Utilities

Steam: 22.8 kg/m^3 - used for vacuum ejectors and stripping

Heaters: 79,400 kcal/m^3 charge

Electricity: 0.63-1.26 kWh/m^3 charge - used for pumping

5. Waste Streams - Steam vacuum ejectors create both air and liquid emissions. The non-condensable vapors removed by these systems must be discharged. It is reported that these non-condensable vapor emissions may be as much as 370 kg per 1000 m^3 of vacuum unit charge. In addition hydrocarbon vapors escaping from barometric condenser hot wells will also contribute to the air pollution problem. Atmospheric emissions from process heaters also occur and will be discussed in a later section. Modern refineries will attempt to eliminate hydrocarbon emissions resulting from the use of steam ejectors by (1) discharging non-condensable vapors to furnace fire boxes for combustion, and (2) replacing barometric condensers with surface condensers when steam ejectors are used.

Aqueous wastes result from condensation of steam used for (1) stripping during vacuum fractionation, and (2) maintaining fractionator vacuum by ejectors or vacuum jets. Potential contaminants include hydrogen sulfide, phenols, plus soluble and emulsified oils. The quantity of the effluent is equal to the amount of steam used during vacuum distillation, about 23 kg/m^3 charge. Aqueous effluents from this process can be eliminated if steam stripping is not utilized and if a mechanical vacuum system rather than a steam ejector is utilized.

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas.

Hydrogen Production

1. Function - Hydrogen is a by-product from several refining processes. One of the most common is catalytic reforming, which produces hydrogen that is available as feed for other processes. However, a refinery with a large distillate hydrotreater or gas oil hydrocracker will require additional high purity hydrogen.

   A steam-hydrocarbon reforming process is commonly used for hydrogen production. Hydrocarbons (ranging from methane to naphtha) and steam are catalytically reacted in a high-temperature reactor. The gas from the reactor contains hydrogen, steam, carbon monoxide, and carbon dioxide, and is passed through a shift reactor where CO and H_2O are catalytically reacted to form carbon dioxide and more hydrogen.

   Steam-hydrocarbon reforming will probably be replaced by partial oxidation of heavy oils as a method of hydrogen production. The light hydrocarbons used as feed for the steam-hydrocarbon reforming process are more economically suited for use in other processing units such as alkylation and catalytic reforming.

2. Input Materials - Feed to this unit consists of a desulfurized light hydrocarbon stream ranging from methane to light naphtha. Most of the feed is produced in the naphtha hydrodesulfurization unit and the acid gas removal unit.

3. Operating Parameters - The following conditions are typical of the reformer section:

   Temperature: 760-870°C

   Pressure: 20.3 kg/sq cm

   A nickel catalyst is commonly employed in the reformer, and an iron catalyst is used in the shift reactor.

4. Utilities -

   Heaters: 475,000 kcal/m^3 feed

   Electricity: 25 kWh/m^3 of feed - used for compression and pumping

5. Waste Streams - This closed process produces no air or liquid emissions other than fugitive emissions from leaks. Process heaters are employed. Air emissions from heaters will be discussed in a separate section.

6. EPA Source Classification Code - None exists.

7. References -

(1) Beavon, David K. and T. R. Roszkowski, "Modern Hydrogen Manufacture", Proc. Amer. Chem. Soc., Div. of Petroleum C51 (1971).

(2) "Hydrocarbon Processing SNG/LNG Handbook", Hydrocarbon Proc. 52 (4), (1973).

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas.

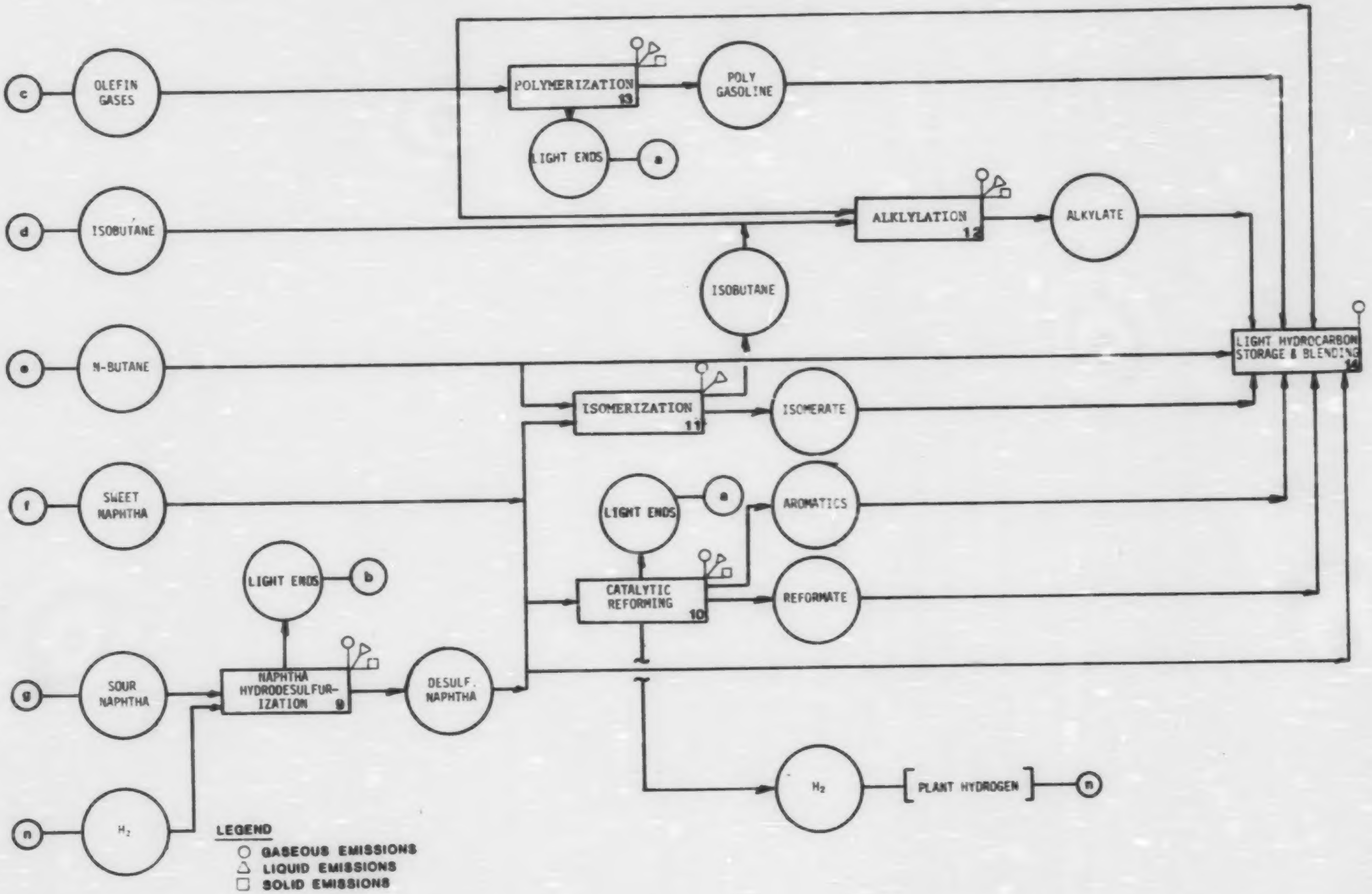
(4) Voogd, J. and Jack Tielrooy, "Improvements in Making Hydrogen", Hydrocarbon Proc. 46(9), 115(1967).

Light Hydrocarbon Processing

Light hydrocarbon processing is a term chosen to represent those separation methods and molecular rearranging techniques used to upgrade the octane ratings of naphthas and all lighter hydrocarbons. The improved products from each of the individual processing units (or modules) are stored and then used in gasoline blending. There are six process modules included in light hydrocarbon processing. Of these six modules, four are direct conversion units, one is a preparation unit, and one a storage and blending unit. These are shown schematically in Figure 2.

The four direct conversion modules are polymerization, alkylation, isomerization, and catalytic reforming. Of these, polymerization is being phased out since the feedstocks to this unit are olefinic gases. In recent years, demand for olefinic gases as a feedstock to the petrochemical industry has precluded the use of these valuable components as a raw material in the manufacture of gasoline.

The remaining two modules are basically preparation and storage units. Naphtha hydrodesulfurization is the preparation unit used to remove sulfur and nitrogen from the naphtha feed since these compounds act as poisons to all downstream catalysts. Light hydrocarbon storage and blending is the sixth and last module considered under this segment.


c
OLEFIN GASES
POLYMERIZATION 13
POLY GASOLINE
LIGHT ENDS
a
d
ISOBUTANE
ALKLYLATION 12
ALKYLATE
ISOBUTANE
e
N-BUTANE
LIGHT HYDROCARBON STORAGE & BLENDING 14
ISOMERIZATION 11
ISOMERATE
f
SWEET NAPHTHA
LIGHT ENDS
a
AROMATICS
LIGHT ENDS
b
CATALYTIC REFORMING 10
REFORMATE
g
SOUR NAPHTHA
NAPHTHA HYDRODESULFUR-IZATION 9
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LEGEND
○ GASEOUS EMISSIONS
△ LIQUID EMISSIONS
□ SOLID EMISSIONS

FIGURE 2. REFINERY LIGHT HYDROCARBON PROCESSING

Naphtha Hydrodesulfurization

1. Function - The naphtha hydrodesulfurization (HDS) unit is used to desulfurize and denitrogenate the naphtha split that comes directly from crude distillation. Both sulfur and nitrogen must be removed to a high degree because naphtha is used as a feed to the isomerization unit, catalytic reforming unit, and other catalytic units which are extremely susceptible to catalyst poisoning by sulfur and nitrogen.

   Gaseous phase naphthas are mixed with a hydrogen-rich gas and heated to reaction temperature. The mixture is then passed through a fixed-bed, non-noble metal catalyst. Under catalytic influence, organic sulfur and nitrogen compounds break down to form hydrogen sulfide and ammonia. Some cracking of naphthas into lighter fractions will occur as a side reaction.

   The hot effluent from the reactor passes through cooling heat exchangers and then to a high pressure separator where hydrogen flashes off and is recycled to the feed stream. The liquid from the separator is sent to a fractionator where hydrogen sulfide, ammonia, and any light hydrocarbons boil off and are sent to an amine unit for removal of the acid gases. The hydrotreated naphtha is split into specified boiling point fractions or continues into the isomerization or reformer reactor sections.

2. Input Materials - Feed to the naphtha HDS unit is sour naphtha directly from the crude distillation column. The normal boiling point range for naphtha is 38-220°C.

   Hydrogen is also used as a raw material in the HDS unit. Hydrogen is produced as a by-product from other process units within the refinery and is piped to the HDS unit to be used in removing sulfur and nitrogen from the naphtha.

3. Operating Parameters - The operating conditions of the naphtha hydrodesulfurization unit will vary depending on the composition of the feed to the unit. However, the operating parameters will fall within the following ranges:

   Temperature: 315-430°C

   Pressure: 2.1 to 6.9 MPa (300-1000 psi)

   The catalyst used is a cobalt-molybdenum catalyst.

4. Utilities -

   Heater fuel: 56,950 kcal/m^3 naphtha (36,000 Btu/bbl)

   Electricity: 16.4 kWh/m^3 naphtha (2.6 kWh/bbl)

Cooling water: 6300 ℓ water/m^3 naphtha (264 gal/bbl)

Steam Usage: 86-258 kg/m^3 (30-90 lb/bbl) if steam stripper used
14 kg/m^3 (5 lb/bbl) without steam stripper.

5. Waste Streams - Naphtha hydroesulfurization is similar to most refinery operations in that the system is closed. The only emissions from this process are those associated with catalyst regeneration, which occurs approximately twice a year. During catalyst regeneration, a steam-air mixture is used to burn off undesirable carbon buildup on the catalyst. This process releases copious quantities of carbon monoxide for a short period. A liquid stream of sour water is also released during catalyst regeneration due to condensation inside the reactor. The catalyst has a useful life of about five years. At the end of this period, it is either sold to a reclaimer of precious metals or disposed of as a solid waste. There is also the potential for hydrocarbon leaks from this unit as from all pressurized units in a refinery.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), (1974).

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle - Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Catalytic Reforming

1. Function - Catalytic reforming is used to convert low octane naphthas into high octane gasoline blending components called reformates. Some reformates have very high concentrations of aromatics which can be extracted for petrochemical use. Several reactions occur during the reforming process including paraffin hydrocracking, parraffin dehydrocyclization, paraffin isomerization, naphthene dehydrogenation and naphthene dehydroisomerization. Hydrogen is a by-product of the dehydrogenation reactions.

   The desulfurized naphtha feedstock is mixed with hydrogen and heated via heat exchangers to near reaction temperatures. The mixture then passes through a series of alternating furnaces and fixed bed catalytic reactors (usually three or four). The furnaces maintain the reaction temperatures between platinum-rhenium catalyst beds. In the reactors, paraffins and naphthenes are dehydrogenated to form higher octane compounds, including aromatics.

   The reactor effluent is cooled in heat exchangers and passes through a separator where hydrogen is flashed off and withdrawn. Some of the hydrogen is recycled, but this process produces more hydrogen than it consumes. The net production of hydrogen is available for use in other refinery processes.

   The liquid from the separator is taken to a fractionator where the C_1 - C_4 fraction is removed. The reformate stream is then either sent to storage as a gasoline blending component, or separated into boiling ranges such as light reformate, aromatic concentrate and heavy reformate. The aromatic concentrate or some portion of full range reformate can be processed through a liquid-liquid aromatic extraction unit.

   Growing production of unleaded gasoline plus limits on the lead content of other gasolines will increase the refining industry's dependence on reforming as a source of high octane (100 + Rcl) gasoline.

2. Input Materials - The feedstock to a catalytic reforming unit is desulfurized naphthas. Even though hydrogen is a by-product of this system, it is recylced with the naptha feedstock; thus, in this sense hydrogen is an input feed. A platinum-rhenium catalyst is used.

3. Operating Parameters -

   Temperature: 427-482°C

   Pressure: 7.0-14.0 kg/sq cm (100-450 psi)

Pressure is the more sensitive parameter and controls the relative amounts of dehydrogenation and hydrocracking reactions. Operating conditions will depend on whether the product is to be used as a petrochemical feedstock or as a gasoline blending component. The nature of the feedstock will also affect choice for operating conditions, since heavy naphthas are usually fed when making gasoline and light naphthas when making aromatics for the petrochemical industry.

4. Utilities -

Furnaces: 408,000 kcal/m^3 (258,000 Btu/bbl)

Electricity: 8.2 kWh/m^3 - required for compressing feed and recycle stream

Cooling water: 10,500 ℓ water/m^3 feed

5. Waste Streams - Again, this process unit is a closed system. The only continuous emissions are those from the process heaters (discussed later) and possible hydrocarbon leaks. There are emissions during the catalyst regeneration period. However, this is an infrequent occurrence and emissions can be considered negligible.

There are some catalytic reforming units that have a continuous catalyst regeneration system. Emissions from this source are estimated to range from 0.005-0.05 kg CO/m^3 (0.002-0.02 lb/bbl). This source may also be considered negligible.

6. EPA Source Classification Code - 3-06-013-01.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), (1974).

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle - Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Isomerization

1. Function - Isomerization units are used to convert n-butane, n-pentane, and n-hexane into their respective isoparaffins. Isobutane that is formed from this process is used as a feedstock for alkylation. Isopentane and isohexane have sufficiently high octane ratings to be used directly as blends for gasoline.

   The feedstock to the isomerization unit must be both dehydrated and desulfurized. The sweet, dry feedstock is mixed with hydrogen and organic chloride. The mixture is then heated to reaction temperature and passed over a catalyst in the hydrogenation vessel where any unsaturated hydrocarbons (e.g., benzene, olefins) are hydrogenated. The hydrogenation reaction need not occur in a separate vessel but may be a part of the isomerization reactor vessel. A chlorinated platinum-aluminum oxide catalyst converts the straight chain hydrocarbons into isoparaffins.

   The effluent product is then cooled and passes to a high pressure separator where recycle hydrogen flashes off. The liquid from the separator passes to a stripper column where the organic chlorides are removed. The product isoparraffins then pass through a neutralization vessel. The next processing steps vary from unit to unit and result in the separation of the normal and iso-paraffins. The normal paraffins are generally recycled to the reactor while the isoparaffins are sent on to alkylation (isobutane) or gasoline blending (isopentane, isohexane).

2. Input Materials - The feedstocks to these units are normal butane and light naphtha fractions containing pentanes and hexanes. The feed must be both desulfurized and dehydrated to prevent fouling the platinum - aluminum oxide catalyst used in this reaction.

   Hydrogen must also be considered a feedstock to the isomerization process. The purpose of the hydrogen is to hydrogenate unsaturated compounds to prevent polymerization. Polymerization reaction would both ruin product quality control and possibly retard catalyst activity.

3. Operating Parameters - The desired reactions occur at the following conditions:

   Temperature: 240-255°C

   Pressure: 21-28 kg/sq cm (300-400 psi)

4. Utilities -

   Fired heaters: 47,000-108,000 kcal/m^3 feed (30,000-68,000 Btu/bbl)

   Electricity: 7.5 kWh/m^3 (1.2 kWh/bbl) - required to compress feed to operating pressure

   Steam: 58-72 kg/m^3 (20-25 lb/bbl) - needed to run the stripper column

5. Waste Streams - Isomerization is a closed process with no air emissions and no liquid effluents other than the aqueous wastes associated with the neutralization step. There are atmospheric emissions from the heaters, but these will be covered in a later section. Also, the possibility always exists for fugitive hydrocarbon leaks.

The catalyst is generally replaced after two years' service and, because of the intrinsic value of the platinum, is sold to salvage dealers. Thus, the catalyst is not a solid waste disposal problem to the refinery.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbood", Hydrocarbon Proc. 53(9), (1974).

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle - Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Alkylation

1. Function - Alkylation units are used to produce a high octane component for gasoline blending. Alkylation is the chemical combination of two hydrocarbon molecules to form one molecule of higher octane rating. An olefin (propylene, butylene and amylene) and an isoparaffin (usually isobutane) are catalytically reacted over either 98% sulfuric acid or 75-90% hydrofluoric acid to produce a high octane component known as alkylate.

A dry olefinic feed is mixed with excess isobutane and contacted with the liquid catalyst in the reaction vessel where alkylation occurs. The reactor effluent is separated into hydrocarbon and acid phases in a settler. The acid is returned to the reactor. The alkylate is then processed further.

Both the sulfuric acid and hydrofluoric acid processes include distillation sections of varying configurations to separate the alkylate product from excess isobutane, normal butane and propane. The isobutane is returned to the reactor section. Normal butane and propane are removed from the process.

Reactor effluent from the sulfuric acid process is utilized in a refrigerant cycle to cool the reactors. Acid and organically combined sulfur in the reactor effluent are removed by caustic scrubbing before distillation. The alkylate, normal butane, and propane products from the distillation section are also caustic scrubbed.

Hydrofluoric acid and organically combined fluorides appear in the propane and alkylate streams from the HF process. A hot bauxite treatment is commonly used to reduce combined fluorides to less than 10 ppm in the propane stream. The use of direct-fired furnaces for deisobutanizer column reboilers provides thermal defluorination of the alkylate product. Propane, n-butane and alkylate product streams are also caustic scrubbed.

Hydrofluoric acid units include an acid regenerator to maintain acid purity by fractionating acid from tar and a constant boiling mixture of acid and water. Acid recovery processes are rarely included in sulfuric acid units. Spent acid from the process is generally exchanged for fresh acid from an acid supplier.

There has been some interest in the alkylation of isobutane with ethylene using an aluminum chloride catalyst complex. However, the process is not commercially important at the present time. The catalyst is more difficult to handle and regenerate than HF and H_2SO_4 catalysts and ethylene is generally a more expensive feedstock.

Since the alkylation process is required to convert by-products of catalytic cracking to gasoline components, it is a standard unit in refineries with catalytic crackers. Alkylate is also one of the highest octane components in the gasoline pool. However, the units are expensive to build and to operate. Any future growth in alkylation capacity will come only after significant growth in catalytic cracking capacity or changes in cracking yields.

2. Input Materials - Isobutane is mixed with an olefin (propylene, butylene and amylene) or mixed olefin feed to form the alkylate. The olefins are catalytic cracking by-products. Isobutane is obtained from crude, from NGL, and as a product of hydrocracking and isomerization processes. The isobutane required varies from 1.0 to 1.33 vol C_4/vol olefin depending on olefin and catalyst type.

   Catalyst make-up requirements vary from 40-125 kg/m^3 alkylate (14-44 lb/bbl) for sulfuric acid units. Hydrofluoric acid make-up requirements vary from 0.3-0.6 kg/m^3 alkylate (0.1-0.2 lb/bbl).

3. Operating Parameters - The two catalyst processes for alkylation differ significantly in operating temperatures.

   Temperature: 10.0-16.0°C for sulfuric acid catalyst processes
   27.0-32.0°C for hydrofluoric acid catalyst processes

   Pressure: 7-10.5 kg/cm^2 (100-150 psi) for either system.

4. Utilities -

   Steam: 286-858 kg stream/m^3 product - used to fractionate the intermediate product

   Electricity: 3.0-30. kWh/m^3 (0.5-5.0 kWh/bbl) -- used to compress feed gases. If refrigeration is required (sulfuric acid system), the electricity requirements will be on the high side of this range.

5. Waste Streams - Alkylation processes are generally closed systems with no process vents to the atmosphere, except those from fired heaters which are discussed in a following section. In some HF units, there can be a process vent from the depropanizer accumulator for releasing non-condensable ethane from the system. However, it is common practice to provide a closed system for all possible discharges containing HF, including vents from pumps, exchangers and all equipment in acid service. This system discharges to an alkaline scrubber where HF is removed before (exhausting to atmosphere or blowdown system). Spent caustic, lime slurry, or potassium hydroxide scrubbing is used. The recovered fluoride is landfilled.

HF units also produce a waste stream from the acid regenerator, usually in the form of a sludge. This material is either incinerated or treated with alkaline solution to recover the fluoride as a solid waste to be landfilled.

The sulfuric acid process produces liquid wastes associated with water and caustic scrubbing of feed and product streams. These wastes are generally processed in the refinery's neutralization and waste water treating facilities.

6. *EPA Source Classification Code* - None exists.

7. *References* -

(1) Anderson, R. F., "*Changes Keep HF Alkylation Up-To-Date*," *Oil and Gas Journal, 72*(2), 78 (1974).

(2) "Hydrocarbon Processing Refining Processes Handbook", *Hydrocarbon Proc. 53*(9), (1974).

(3) Nack, H., et al., *Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities*, EPA 650/2-74-048, Columbus, Ohio, Battelle - Columbus Labs., 1974.

(4) Nelson, W. L., *Petroleum Refinery Engineering*, McGraw-Hill, Fourth Edition, 1958.

(5) Radian Corporation, *A Program to Investigate Various Factors in Refinery Siting*, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

(6) Sims, Anker V., *Field Surveillance and Enforcement Guide for Petroleum Refineries*, Final Report, EPA 450/3-74-042, Contract No. 68-02-0645, Pasadena, California, Ben Holt Co., 1974. PB 236-669.

Polymerization

1. Function - The polymerization unit is used to produce a high octane gasoline or petrochemical feedstock from olefin gases. It performs essentially the same function as an alkylation unit. However, the major difference between the two units is that alkylation requires an olefin and an isoparaffin feed while polymerization requires two olefin gases as feed. With the rising importance of olefins as feedstock to the petrochemical industry, polymerization is being phased out as a refining process. In other words, there are more economical means to upgrade octane ratings of gasoline components.

   Poly gasolines (the polymerization product) are formed by passing two olefin gases over a catalyst where the polymerization reaction occurs. The most common catalyst used is phosphoric acid. The reaction is exothermic so outside energy is required only on start-up. After the reaction, the gases pass through a heat exchanger with incoming gases. The gases are then sent to a fractionator to be split into various components.

2. Input Materials - The feedstock to the polymerization unit is any combination of olefins such as ethylene, propylene, butylene, and amylene. These gases are usually products of gas processing within the refinery.

3. Operating Parameters - Conditions inside the reactor are as follows:

   Temperature: 135-190°C

   Pressure: 35 kg/sq cm (500 psi)

   The catalyst most commonly employed is phosphoric acid or phosphoric acid-impregnated pellets.

4. Utilities - Utility requirements are low for this unit.

   Steam - 57 kg/m^3 feed (20 lb/bbl) - required for fractionation of the product.

   Electricity - 7.5 kWh/m^3 (1.2 kWh/bbl) - required to pump the liquid feed.

5. Waste Streams - The polymerization unit is similar to other process units in a refinery in that it is a closed system with no atmospheric emissions. The only liquid emission is the phosphoric acid catalyst which may be washed out during maintenance periods. Maintenance periods are infrequent, occurring about once every two years. If the phosphoric acid is supported on a solid, there will be a solid waste disposal problem which must be dealt with during the maintenance periods.

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA-650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Nelson, W. L., Petroleum Refinery Engineering, McGraw-Hill, Fourth Edition, 1958.

Light Hydrocarbon Storage and Blending

1. Function - The purpose of light hydrocarbon storage and blending is to store the various products of the light hydrocarbon processing section until blending requirements are determined. Then blending commences by mixing various components in a header to achieve a product of desired characteristics. The product flows from the blending header to separate storage to await sale.

   The most common blending operation involves the final step in gasoline manufacture. All the products of the light hydrocarbon processing section are components of gasoline. The various individual products such as catalytic gasoline, alkylates, isomerates, aromatics, reformates, and butane are stored separately until they are blended together along with purchased materials such as tetraethyl lead and dye to form marketable gasoline.

   All the intermediate products and the final product have sufficiently high vapor pressure that they must be stored in floating roof tanks or vapor recovery tanks. Of course, the very light ends such as butane, propane, and ethane are stored in pressure vessels.

2. Input Materials - Separate storage facilities are required for each of the products of the various light hydrocarbon processing units. There must be storage available for butane, propane, catalytic gasoline, alkylates, isomerates, aromatics, reformates, and final products such as the various grades of gasoline.

3. Operating Parameters - All light hydrocarbon storage must be carried out in vapor control tanks. These tanks are most generally floating roof tanks but may involve vapor recovery tanks. The products that are gases at ambient temperatures must be stored in pressure vessels.

   Temperature: Ambient temperature

   Pressure: Ambient pressure unless stored in pressure vessels in which case pressure will be vapor pressure of stored product.

4. Utilities - Utility requirements are simply those needed to pump the liquid products. These are negligible when compared to other refinery operations.

5. Waste Streams - The waste stream from light hydrocarbon storage occurs as a result of liquid evaporation from wetted walls and evaporation around the roof seals. This value averages about 0.004 kg hydrocarbon per day per 1000 liters storage capacity.

6. EPA Source Classification Code

   Gasoline storage 4-03-002-01

7. References -

(1) Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd Ed., AP-42, Research Triangle Park, N.C., 1973.

(2) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

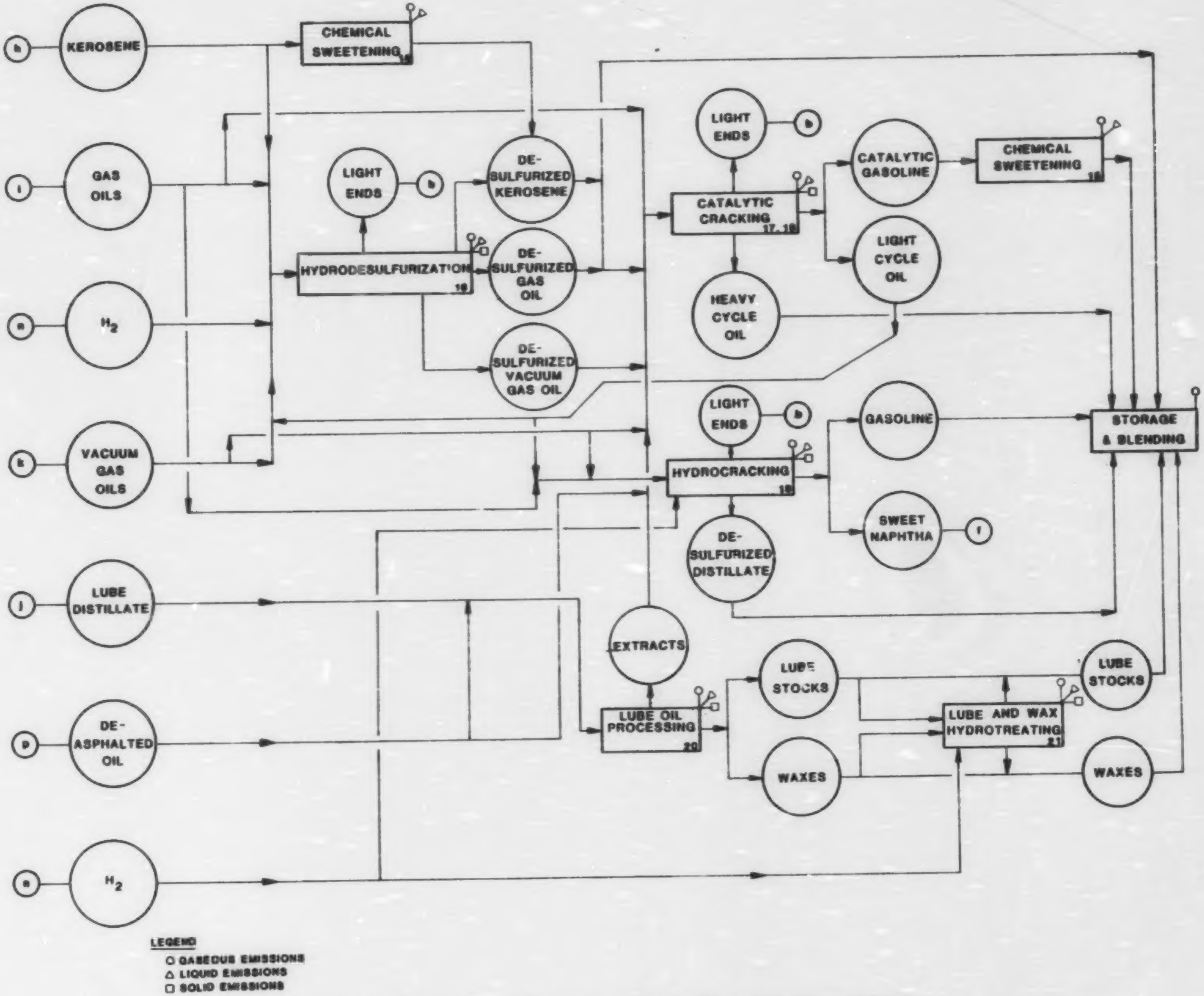
Middle and Heavy Distillate Processing

Middle and heavy distillate processing refers to the treatment of kerosenes, virgin and cracked gas oils and lube oils. These oils cover a wide boiling range, 230-560°C (450-1050°F). Seven modules are considered in this segment. Two modules are concerned with reducing sulfur levels in fuels, two with catalytic cracking, two with lube oil and wax processing and one with the storage operation. These are shown schematically in Figure 3.

The two sulfur treating modules are chemical sweetening and hydrodesulfurization. Chemical sweetening processes are utilized to remove odiferous sulfur compounds like mercaptans from relatively low sulfur content streams such as kerosene and catalytic gasoline. Catalytic hydrodesulfurization is a process used extensively to make high quality, low sulfur fuels. The process removes up to 90% of the sulfur in the feed, which is generally kerosenes or virgin and cracked light gas oils. The process is also used to pretreat catalytic cracking feedstocks.

Catalytic cracking processes convert gas oils to lighter products, primarily gasoline. Fluid bed catalytic cracking is the most widely used process. Moving bed catalytic cracking is a variation of the same process. Hydrocracking is a high severity process which combines cracking and hydrogenation, handles a broad range of feeds, and produces varying ratios of gasoline and light fuel oils.

The lube oil processing module describes the processes used to make high quality lubricating oils and waxes.


h
KEROSENE
i
GAS OILS
n
H_2
k
VACUUM GAS OILS
j
LUBE DISTILLATE
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DE-ASPHALTED OIL
n
H_2
CHEMICAL SWEETENING 15
LIGHT ENDS
b
HYDRODESULFURIZATION 19
DE-SULFURIZED KEROSENE
DE-SULFURIZED GAS OIL
DE-SULFURIZED VACUUM GAS OIL
LIGHT ENDS
b
CATALYTIC CRACKING 17, 18
HEAVY CYCLE OIL
CATALYTIC GASOLINE
LIGHT CYCLE OIL
CHEMICAL SWEETENING 15
LIGHT ENDS
b
HYDROCRACKING 19
DE-SULFURIZED DISTILLATE
GASOLINE
SWEET NAPHTHA
f
STORAGE & BLENDING
EXTRACTS
LUBE OIL PROCESSING 20
LUBE STOCKS
WAXES
LUBE AND WAX HYDROTREATING 21
LUBE STOCKS
WAXES
LEGEND
○ GASEOUS EMISSIONS
△ LIQUID EMISSIONS
☐ SOLID EMISSIONS

FIGURE 3. REFINERY MIDDLE AND HEAVY DISTILLATE PROCESSING

Chemical Sweetening

1. Function - Chemical sweetening is used to remove mercaptans, hydrogen sulfide and elemental sulfur from catalytic gasolines and light distillates. Mercaptans impart a foul odor to petroleum products, increase requirements for tetraethyllead additions to achieve octane specifications in gasoline, and, in the presence of elemental sulfur, cause corrosion. There are at least eleven different processes for sweetening hydrocarbons. Three of the most widely used proprietary processes are Merox, Locap and Bender sweetening.

   Some processes remove the mercaptans from the hydrocarbon stream by extraction with caustic. The caustic solution often contains solubility promoters such as alkyl phenols, cresols and naphthenic acids. Extraction is generally confined to lighter mercaptans (methyl and ethyl mercaptan). Conversion processes oxidize higher molecular weight mercaptans to the less odiferous disulfide in the presence of air, alkali and a catalyst. Many processes combine an extraction step with a conversion step. Oxidizing agents and catalysts include lead sulfide and oxide, copper chloride, and hypochlorites.

2. Input Materials - Straight run and catalytic gasolines, kerosene, jet fuels and other light distillates are the hydrocarbon streams generally charged to sweetening units. Treating materials include caustic, various solubility promoting chemicals, oxidizing agents and catalysts, and catalyst regenerants.

3. Operating Parameters - The operating conditions will depend on the product being processed but should be approximately:

   Temperature: Ambient - 65°C

   Pressure: 1.4 kg/sq cm

4. Utilities - Pumping costs only

   Electricity: 0.06 (1) - 0.25 kWh/m^3

5. Waste Streams - Emissions vary depending on the process. Some sweetening processes utilize air blowing to regenerate extraction/oxidation solutions. No appreciable hydrocarbon emissions result. Aqueous emissions are common. Water washing is frequently employed after contacting hydrocarbons with caustic. The use of some oxidizing agents, hypochlorite for example, results in waste water discharges. However, these sources are usually handled without significant problems by waste water treating facilities.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", *Hydrocarbon Proc*. 53(9), (1974).

(2) Nack, H., et al., *Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities*, EPA 650/2-74-048, Columbus, Ohio, Battelle - Columbus Labs., 1974.

Hydrodesulfurization

1. Function - The hydrodesulfurization process is used for desulfurization, denitrogenation, olefinic and aromatic hydrogenation and demetallization of distillates and gas oils. The process is used extensively to produce high quality, low sulfur kerosene and light gas oils for the production of jet fuels, diesel fuels and heating oils. The process is also used to a lesser extent to treat heavy gas oils for blending low sulfur heavy fuel oils or for high quality catalytic cracking feed.

   The oil is mixed with make-up and recycle hydrogen, heated, and charged to a fixed bed reactor containing a non-noble metal catalyst. The reactions occur in an essentially liquid phase. Sulfur and nitrogen react with hydrogen to form H_2S and NH_3. A hydrogen-rich stream is flashed from the reactor product in a high pressure separator and is recycled. Reactor product flows to a low pressure separator where most of the H_2S, NH_3 and light ends are recovered. The oil product is then stream stripped or fractionated to remove the remaining impurities.

2. Input Materials - Feed to a hydrodesulfurization unit may be kerosene, light gas oil or distillates (including cracked gas oils) or heavy gas oils (straight-run or cracked).

   Hydrogen requirements vary with the feed type and degree of desulfurization desired. Kerosene hydrotreating requires around 70 m^3H_2/m^3 (400 SCF/BBL) while gas oils require up to 300 m^3H_2/m^3 (1700 SCF/BBL).

   The catalyst is generally a non-noble metal catalyst such as nickel or cobalt molybdenum.

3. Operating Parameters - The operating conditions in the reactor are:

   Temperature: 205-416°C (390-800°F)

   Pressure: 35-56 kg/cm^2 (500-800 psi)

4. Utilities -

   Electricity: 3-58 kWh/m^3 (pumping and compression)

   Heater Fuel: 0-110,000 $kcal/m^3$ (0-70,000 Btu/bbl)

   Steam: 2.8-29 kg/m^3 (1-10 lb/bbl)

   Cooling Water: 400 $liters/m^3$ (160 gal/bbl)

5. Waste Streams - Hydrodesulfurization is similar to most refinery operations in that the system is closed. The only atmospheric emissions associated with those processes are from the fired heaters (discussed in a later module) and those from catalyst regeneration. Catalyst regeneration occurs about twice each year.

Other emissions include hydrocarbon leaks from flanges and valves (fugitive emissions) and a sour water stream from the steam stripping operation.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), 1974.

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Fluid Bed Catalytic Cracker

1. Function - The fluid bed catalytic cracking process is one of the most versatile and widely used in the refining industry. The process uses a solid, finely powdered zeolitic catalyst that when mixed with a gas has transport properties similar to those of a liquid. Feedstocks can vary from naphtha boiling-range materials to vacuum residuals. Products include, but are not limited to, LPG, olefins, high octane gasoline, petrochemical raw materials, distillate blending components, and carbon black oil. The process is commonly used to convert heavy virgin, vacuum, and coker gas oils to lighter products, with an emphasis on gasoline and distillate blending components in most refineries.

Preheated feed is introduced into the bottom of a vertical transfer line, or riser, and mixed with hot, regenerated catalyst. The catalyst-oil mixture flows up the riser into a reactor/separator with cracking reactions occuring in both the riser and reactor/separator. Cyclones inside the reactor separate the gaseous reaction products from the catalyst. Reaction products flow from the top of the reactor section to a fractionation section while spent catalyst flows from the bottom of the reactor to the regenerator.

The spent catalyst is steam stripped to remove residual hydrocarbon as it leaves the reactor for the regenerator. Inside the regenerator, the coke deposited on the catalyst as a by-product of the cracking reactions is burned off in a controlled combustion process with preheated air. The degree of combustion varies with unit design from essentially complete combustion to CO_2 to some desired ratio of CO_2/CO. The hot, regenerated catalyst then flows to the bottom of the riser to mix with incoming feed and complete the catalyst cycle.

The hot flue gas leaves the regenerator, passing through several sets of cyclones and/or an electrostatic precipitator to remove entrained catalyst fines. Most refiners make an effort to recover the energy in the flue gas. The heat of the gas is recovered by producing steam. Flue gas containing appreciable quantities of CO is burned in a steam producing furnace called a CO boiler. Some refiners utilize the pressure energy of the gas to drive rotating equipment, the regenerator air blower for example.

The reaction products are generally separated by distillation into an overhead product of gasoline boiling range and lighter components, a middle product of light cycle oil and a bottoms product of heavy cycle oil. The overhead product is fractionated further to yield LPG, olefins and debutanized gasoline. The light cycle oil can be hydrotreated and used as a distillate blending component or used as feed to a hydrocracking unit. The heavy cycle oil is processed to concentrate entrained catalyst in one portion which is recycled to the riser. The clarified remainder is a highly unsaturated, aromatic oil that can be used in a variety of ways; carbon black oil is one example.

Operating variables for this process cover a wide range of conditions, depending on feed type and quality, desired product mix and individual unit design. The latest designs maximize cracking reactions in the riser, utilizing the reactor section strictly as a separator for rapid disengagement of the catalyst-oil mixture. Riser-cracking promotes maximum gasoline production.

There is a high level of interest in hydrotreating feedstocks before charging to the cracking unit. Hydrotreating the feed reduces sulfur and improves gasoline yields and quality. The need to reduce sulfur emissions and increase unleaded gasoline production indicates that hydrotreating may be more widely used in the future. Another possible future trend is charging residuals, either atmospheric or vacuum or even whole crude oil. A significant limitation here is short catalyst life and unsatisfactory yields due to poisoning of the catalyst by metals.

2. Input Materials - The feed to the fluid bed catalytic cracker may range from naphtha boiling range material to vacuum residuals. The most common feed is composed of virgin and cracked gas oils with a boiling range of 345-570°C.

3. Operating Parameters - There is a range of products produced. The amount of each can be varied by changing the operating conditions. Some typical conditions are as follows:

Reactor -

Temperature: 475-550°C (887-1022°F)

Pressure: 0.7-2.1 kg/sq cm (10-30 psig)

Regenerator -

Temperature: 675-760°C

Pressure: 1.0-2.5 kg/sq cm (15-35 psig)

4. Utilities -

Furnace: 230,000 kcal/m^3 feed (143,000 Btu/bbl)

Electricity: 2.6 kWh/m^3

Steam: if CO boiler is used, the net production of steam is 210 kg/m^3 (73 lb/bbl).

5. Waste Streams - The fluid bed catalytic cracker is one of only three units in a refinery from which there are continuous process emissions. These emissions emanate from the catalyst regenerator and are as follows:

Atmospheric emissions - uncontrolled

Particulates 0.267-0.976 kg/m^3 fresh feed

Sulfur oxides 0.898-1.505 kg/m^3 fresh feed

Carbon monoxide 39.2 kg/m^3 fresh feed

Hydrocarbons 0.630 kg/m^3 fresh feed

Nitrogen oxides 0.107-0.416 kg/m^3 fresh feed

Aldehydes 0.054 kg/m^3 fresh feed

Ammonia 0.155 kg/m^3

Atmospheric emissions - controlled by CO boiler and/or electrostatic precipitator

Particulates 0.036-0.175 kg/m^3 fresh feed

Sulfur oxides 0.898-1.505 kg/m^3 fresh feed

Carbon monoxide - negligible

Hydrocarbons 0.630 kg/m^3 fresh feed

Nitrogen oxides 0.107-0.416 kg/m^3 fresh feed

Aldehydes 0.054 kg/m^3 fresh feed

Ammonia 0.155 kg/m^3 fresh feed

Note that the CO boiler is fired at a low temperature (∿700°C) and thus is not hot enough to consume the other combustibles in the waste stream.

Aqueous wastes include condensed steam from the catalyst steam stripping section. This stream contains hydrogen sulfide, mercaptans, ammonia, and phenols. The reported volume is 120 ℓ water/m^3 feed (5 gal/bbl).

Solid waste consists of spent catalyst and catalyst fines. Catalyst fines captured by the electrostatic precipitator or cyclones amount to 0.23-0.80 kg/m^3 fresh feed (0.08-0.28 lb/bbl). The volume of spent catalyst displaced from circulating inventory is the difference between the catalyst make-up rate and catalyst lost with the flue gas.

Furnace combustion products are discussed in a later section.

6. EPA Source Classification Code - 3-06-002-01.

7. References -

(1) Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd Ed. with Supplements, AP-42, Research Triangle Park, N.C., 1973.

(2) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), 1974.

(3) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(4) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Moving Bed Catalytic Cracker

1. Function - The function of a moving bed catalytic cracker (also called Thermofor Catalytic Cracking Units, TCCU) is the same as that of the fluid bed unit. The process uses a synthetic bead catalyst to crack gas oils into a wide variety of lighter hydrocarbons such as LPG, olefins, gasoline, and distillate blending components.

   The rather large catalyst beads (∿.0.5 cm) flow by gravity into the top of the reactor where they contact a mixed vapor - liquid feed. The oil-catalyst mix flows down through the reactor to a disengaging zone where catalyst and oil separate. The gaseous reaction products flow out of the reactor to the fractionation section. The catalyst continues downward through a purge zone where it is steam stripped of residual hydrocarbon. The purged spend catalyst then flows by gravity through the kiln, or regenerator, where coke is burned from the catalyst. After regeneration, the catalyst is cooled to remove excess heat, then flows into a lift pot where it is forced up a riser by low pressure air to a separator. Catalyst from the separator is returned to the reactor to complete the catalyst cycle.

   Reaction products are separated into wet gas, gasoline, and light and heavy cycle fractions. The wet gas is eventually processed in a gas plant. The gasoline stream is debutanized, sweetened and sent to storage. The light cycle can be hydrotreated for use as a distillate blending stock or used as hydrocracker feed. Some portion of the heavy cycle fraction will be recycled to the reactor while the remainder is generally used as a heavy fuel oil blending component.

   The moving bed process is no longer competitive with the fluid process in most refining applications. It is doubtful that any new units will be constructed except under special circumstances. However, there are many moving bed units in operation, particularly in older or smaller refineries, that will not be replaced in the immediate future. This process, like the fluid process, is very versatile and there is widespread interest in using these units to process residuals and whole crude.

2. Input Materials - Feed to the moving bed catalytic cracker is the same as feed to a fluid bed catalytic cracker. Usually the feedstock is gas oils from the crude and vacuum stills, but it may range from kerosene to residual oils.

   A typical boiling range for the feed is 345-570°C.

3. Operating Parameters - The operating conditions should be similar to those of a fluidized bed system. Fluidized bed conditions are:

Reactor -

Temperature: 475-550°C

Pressure: 0.7-2.1 kg/sq cm (10-30 psig)

Regenerator -

Temperature: 675-760°C

Pressure: 1.0-2.5 kg/sq cm (15-35 psig)

4. Utilities -

Furnace: 158,000-475,000 kcal/m^3 (100,000-300,000 Btu/bbl)

Electricity: 0.6-9.4 kWh/m^3 (0.1-1.5 kWh/bbl) for air blowing and pumping requirements

Steam: 285 kg/m^3 feed (100 lb/bbl) for steam fractionation

456 kg/m^3 feed may be generated by the hot off gases from the regenerator

5. Waste Streams - The moving bed catalytic cracker has a continuous process emission from the catalyst regenerator and catalyst surge separator with the following atmospheric emissions:

Particulates 0.049 kg/m^3 fresh feed

Sulfur oxides 0.171 kg/m^3 fresh feed

Carbon monoxide 10.8 kg/m^3 fresh feed

Hydrocarbons 0.250 kg/m^3 fresh feed

Nitrogen oxides 0.014 kg/m^3 fresh feed

Aldehydes 0.034 kg/m^3 fresh feed

Ammonia 0.017 kg/m^3 fresh feed

Other waste streams are:

Aqueous emissions: 285 kg/m^3 fresh feed - this is the sour water stream from the steam stripper

Solid wastes: 0.28-0.56 kg/m^3 fresh feed - this is the replacement rate of spent catalyst.

6. EPA Source Classification Code - 3-06-003-01

7. References -

(1) Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, 2nd Ed., AP-42, Research Triangle Park, N.C., 1973.

(2) "Hydrocarbon Processing Refining Processes Handbook", *Hydrocarbon Proc*. *53*(9), 1974.

(3) Nack, H., et al., *Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities*, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(4) Radian Corporation, *A Program to Investigate Various Factors in Refinery Siting*, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Hydrocracking

1. Function - Hydrocracking is a combination of catalytic cracking and hydrogenation. Heavy feedstocks are converted into lighter fractions in a high temperature reaction in the presence of high pressure hydrogen and a catalyst. Hydrocracking is generally used to supplement the catalytic cracking process. A hydrocracker costs more to build and operate than a fluid bed catalytic cracker. However, the hydrocracker can handle heavier fractions and cracked gas oils better and the products contain no unsaturated hydrocarbons. Many refiners use light cycle oil from the catalytic cracking process as a primary feed to the hydrocracking unit.

   The hydrocracker can employ either one or two reactor stages. A unit designed to treat a feed of relatively low sulfur and nitrogen content and low unsaturate or aromatic composition can utilize a single reactor. If the feed is relatively high in sulfur, nitrogen, unsaturates and aromatics, two reactors are required. The first reactor functions as a hydrodesulfurizer, converting sulfur and nitrogen into H_2S and NH_3 which are removed in a separator before charging the feed to the second stage.

   Reactor effluent passes through high and low pressure separators to remove H_2, which is recycled, and light components. The product stream is then fractionated into various components. The hydrocracking process can yield a variety of products. Many refiners utilize the process to produce saturated light ends like normal and iso butane, a light gasoline fraction for blending, a naphtha fraction for reformer feed, a high quality kerosene for jet fuel, or distillate for diesel/home heating fuel. Heavier material is recycled. Some refiners recycle anything heavier than naptha to extinction.

2. Input Materials - Virgin and/or cracked gas oils containing some sulfur and nitrogen impurities is the usual feed to a catalytic hydrocracker. The boiling range is 345-570°C. Hydrogen is needed at the rate of 250 to 375 cubic meters per cubic meter of feed (1,400 to 2,100 scf/bbl). In extreme cases, up to 4000 scf/bbl is required. The catalyst used is cobalt-molybdenum or nickel-molybdenum.

3. Operating Parameters - The operating conditions of a first stage reactor on a typical catalytic hydrocracker are:

   Temperature: 370°C (700°F)

   Pressure: 210 kg/sq cm (3000 psi)

   Operating conditions for the second stage are:

   Temperature: 315°C (600°F)

   Pressure: 105 kg/sq cm (1,500 psi)

4. Utilities -

Electricity: 48 to 88 kWh/m^3 of feed (8.2 to 15 kWh/bbl)

Steam: 28.6 to 46.1 kg/m^3 of feed (10 to 16.1 lb/bbl)

Heater Fuel: 230,000 to 400,000 kcal/m^3 of feed (145,000 to 250,000 Btu/bbl)

Cooling Water: 290 to 1450 liters/m^3 of feed (120 to 600 gal/bbl)

Process Water: 10 liters/m^3 of feed (4 gal/bbl)

5. Waste Streams - There are three sources of emissions to the atmosphere from a catalytic hydrocracker. The major source is the process heaters used in the unit. These emissions are described in a separate module which includes process heaters. Another source of air emissions is the catalyst regeneration operations. This cleaning process releases large quantities of carbon monoxide over a short period of time. The third source of air emissions in the fugitive hydrocarbon leaks which occur around pump seals, relief valves, flanges, valve stems, and compressor seals.

Two liquid waste streams result from this unit: one during periodic catalyst regeneration and the other continuously. The waste stream resulting from regeneration is a sour water stream which is equal to the amount of steam that condenses in the reactor during this time. The continuous liquid waste stream comes from the high pressure separator, the low pressure separator, and the stabilizer accumulator. This stream contains dissolved H_2S and NH_3. It is treated by a sour water stripper before being discharged or reused.

The catalyst in the first stage has a useful life of a couple of years. At the end of its usefulness it is either sold to a reclaimer of precious metals or disposed of as a solid waste.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), (1974).

(2) Sims, Anker V., Field Surveillance and Enforcement Guide for Petroleum Refineries, Final Report, EPA 450-3-74-042, Contract No. 68-02-0645, PB 236 669, Pasadena, CA., Ben Holt Co., 1974.

Lube Oil Processing

1. Function - Narrow boiling-range cuts from the vacuum distillation of reduced crude are used for lubricating oil base stocks. These fractions are refined to increase viscosity indexes, oxidation stability, and resistance to sludge and gum formation by removing aromatics, unsaturates, naphthenes and asphalts. Some lube oil stocks are then dewaxed and the wax deoiled. Solvent treating processes are the most effective and widely used for lube oil refining, oil dewaxing and wax deoiling.

   The most common lube oil refining processes are single solvent processes using furfural or phenol as solvents. The Duo-Sol process uses dual solvents, propane and selecto, a cresylic acid-phenol mixturc. Generally, the oil and solvent are contacted in counterflow towers or multistage contactors. Distillation is used to recover the solvent remaining in the lube oil and to separate solvent from the extract. The solvent is recycled and the extract is used as catalytic cracking feed. The lube oil might be used as blending stock or processed through an oil dewaxing unit.

   The dewaxing process removes wax from lube oils which improves the low temperature fluidity characteristics of the oil. The oil is contacted with solvent and chilled, causing the wax to precipitate. The precipitated wax is separated from the mixture by filtration or centrifuging. The dewaxed oil and solvent are separated by distillation and steam stripping. Solvent is recycled. The wax, usually containing at least 10% oil, is solvent treated again under different conditions to obtain a described wax product of the desired specifications. Refrigeration and filtration are used to recover the wax and solvent. The most widely used solvent for oil dewaxing and wax deoiling is methyl ethyl ketone (MEK) or a mixture of MEK and toluene or benzene. Both operations are frequently combined in one unit using a MEK solvent. Other solvents used in oil dewaxing and wax deoiling are methyl butyl ketone, either alone or mixed with toluene or benzene, and propane.

   Some refiners also solvent treat vacuum resid to recover microcrystalline waxes (petrolatum) which have different crystalline structures and properties than paraffin waxes.

   An old process for treating lube oils, still used to some extent, is to contact the oil with sulfuric acid. The acid reacts with unsaturates and polyaromatics to form a sludge. Clay filtration is used to remove the sludge from the oil.

2. Input Materials - Lubricating oils are narrow boiling - range cuts obtained from vacuum distillation of atmospheric residuum. They are generally fractionated from the 350-540°C portion of the residuum.

3. Operating Parameters - Lube oil refining processes are generally low pressure (<14 kg/cm^2), low temperature (38-120°C) processes. Oil dewaxing and wax deoiling processes are low pressure, (<14 kg/cm^2) low temperature (-40°C to +38°C) processes. Solvent-oil ratios vary with the process type, solvent, and charge properties. The volume ratio is generally in the range from 1.0 to 5.0.

4. Utilities - Oil dewaxing and wax deoiling processes are major energy consumers due to refrigeration and filtration requirements.

   Electricity: 10-60 kWh/m^3 feed (2-10 kWh/bbl)

   Steam: 300-1,000 kg/m^3 feed (100-400 lb/bbl)

5. Waste Streams - Atmospheric emissions are negligible. Lube oil processing can contribute significant BOD loads to refinery waste water treating systems if solvent-rich waste streams enter sewers. However, this contribution has not been quantified.

   If the acid treating/clay filtration process is used, the sludge can be a solid waste problem. Again, the amount of acid sludge and waste clay is unknown.

6. EPA Source Classification - None Exists.

7. References -

(1) Bland, William F., and Robert L. Davidson, eds., Petroleum Processing Handbook, N.Y., McGraw-Hill, 1967.

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(3) Soudek, M., Hydrocarbon Processing, Vol. 53, No. 12, December (1974).

Lube and Wax Hydrotreating

1. Function - Lube oil and wax stocks are hydrotreated to improve product quality. The hydrotreating process is used for viscosity index improvement, desulfurization, denitrogenation, dimetallization, removal of gum forming compounds, and color improvement.

   The oil feed is mixed with make-up and recycle hydrogen and charged to a fixed catalyst bed reactor. Reactor effluent flows through high and low pressure separators to remove first hydrogen for recycle then light ends. The product is then stream stripped to remove any remaining impurities.

   This process can be utilized to improve the quality of refined lube oils and waxes or to treat raw distillates and deasphalted oils. The latter function can replace conventional lube oil processes like solvent refining processes.

2. Input Materials - The feed to a hydrotreating unit can be either solvent refined lube oils and waxes or raw distillates and deasphalted oils. Hydrogen requirements vary from 20 to 30 m^3H_2/m^3 oil (100-200 ft^3/bbl).

   The catalyst is generally a cobalt or nickel-molybdenum base.

3. Operating Parameters - The operating conditions within the reactor are:

   Temperature: 320 to 400°C (600 to 750°F)

   Pressure: 35 to 50 kg/sq cm (500 to 700 psi)

4. Utilities -

   Electricity: 15 kWh/m^3 of feed (2.5 kWh/bbl)

   Steam: 43 to 86 kg/m^3 of feed (15 to 30 lbs/bbl)

   Heater Fuel: 55,500 to 222,000 kcal/m^3 of feed (35,000 to 140,000 Btu/bbl)

5. Waste Streams - Atmospheric emissions which result from the operation of this unit originate from the process heaters, periodic catalyst regeneration, and fugitive hydrocarbon leaks in equipment. The emissions from the process heaters will be discussed in a separate module. Catalyst regeneration involves burning off deposited coke by passing a steam and air mixture through the bed. The resulting gaseous emissions include significant quantities of carbon monoxide. As with all high pressure refinery equipment, a fugitive hydrocarbon emission problem exists. Emissions occur at relief valves, valve stems, flanges, pump seals, and compressor seals.

Liquid waste streams which contain H_2S result from the high and low pressure separators. These streams are passed to a sour water stripper which removes the contaminants from the water. The steam which condenses within the reactor during catalyst regeneration operations is contaminated with H_2S and must be treated in a sour water stripper.

Spent catalyst is either sold to a precious metals reclaimer or disposed of as a solid waste. Catalyst life may be as long as five years, so this disposal problem is not significant.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), 1974.

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-028, Columbus, Ohio, Battelle-Columbus Labs, (1974).

Middle and Heavy Distillate Storage and Blending

1. Function - The purpose of storage is to segregate various hydrocarbon fractions so that they can be blended to desired feedstock characteristics or product specifications. The blending operation can be accomplished by blending individual components in a single tank or by mixing the components in a header. The first method is commonly used to mix feedstocks, while the second method, often called inline blending, is generally used for product blending. Finished products also require some storage capacity.

   Storage capacity in a refinery might be dedicated to a particular service or switched from one service to another. For instance, some gas oils are stored in gas blanketed tanks to prevent quality degradation by oxidation. These tanks remain in the same service year-round. Other tankage might be used to store distillates in gasoline season and gasoline in distillate season.

2. Input Materials - The inputs to middle and heavy distillate storage include untreated kerosenes; light, heavy, and vacuum gas oils; and lube distillates from crude distillation. Treated kerosenes, gas oils, lube oils, and waxes from the hydrodesulfurization, cracking and lube refining processes are also stored.

3. Operating Parameters - The operating conditions are usually ambient temperature and pressure.

4. Utilities - A negligible amount of pumping energy is needed. No other utilities are used.

5. Waste Streams - Blending and storage operations potentially represent the largest single source of hydrocarbon emissions from refineries. Hydrocarbon atmospheric emissions result from the tank batteries used in middle distillate storage. There are three mechanisms by which hydrocarbon emissions occur during storage: breathing losses, working losses, and standing storage losses.

   Breathing and working losses are associated with fixed- or coned-roof tanks and standing storage losses are associated with floating-roof tanks. Regulations require that tanks storing a liquid hydrocarbon with a true vapor pressure from 1.1 to 7.8 mg/m^2 (1.5 to 11.0 psia) be equipped with a floating roof tank. Those tanks storing a hydrocarbon with a vapor pressure below this range may use a fixed roof tank. For this reason, probably only cat gasoline storage will require a floating roof tank.

However, a serious problem occurs when refineries, particularly those in warmer climates, store finished winter gasolines destined for northern markets. Winter gasolines generally have a high vapor pressure component (usually butane) and this mixture would exceed the regulation vapor pressure of 7.8 mg/m^2 (11.0 psia) for floating root tanks. The end result is reduced blending flexibility for the refinery. Finished gasoline is sometimes shipped with less butane than specifications permit in order to comply with environmental constraints.

Assuming "new tank" conditions, the rate of hydrocarbon emissions from gasoline storage in a floating roof tank is 0.0040 kg per day-10^3 liters stored (0.033 lb/day-10^3 gal). For kerosene and fuel oil storage in a fixed roof tank ("new condition"), the hydrocarbon breathing loss amounts to 0.0043 kg per day-10^3 liters stored (0.036 lb/day-10^3 gal). Working losses total 0.12 kg per 10^3 liters throughput (1.0 lb/10^3 gal).

There are no liquid wastes or solid wastes associated with the storage and blending operation.

6. EPA Source Classification Code -

Fixed Roof Tanks:

Hydrocarbon Stored	SCC Number
Kerosene (Breathing losses)	4-03-001-06
Distillate Fuel (Breathing losses)	4-03-001-07
Kerosene (Working losses)	4-03-001-51
Distillate Fuel (Working losses)	4-03-001-52

Floating Roof Tanks:

Hydrocarbon Stored	SCC Number
Gasoline (Standing losses)	4-03-002-01

References -

(1) Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd Ed. with Supplements, AP-42, Research Triangle Park, N.C., 1973.

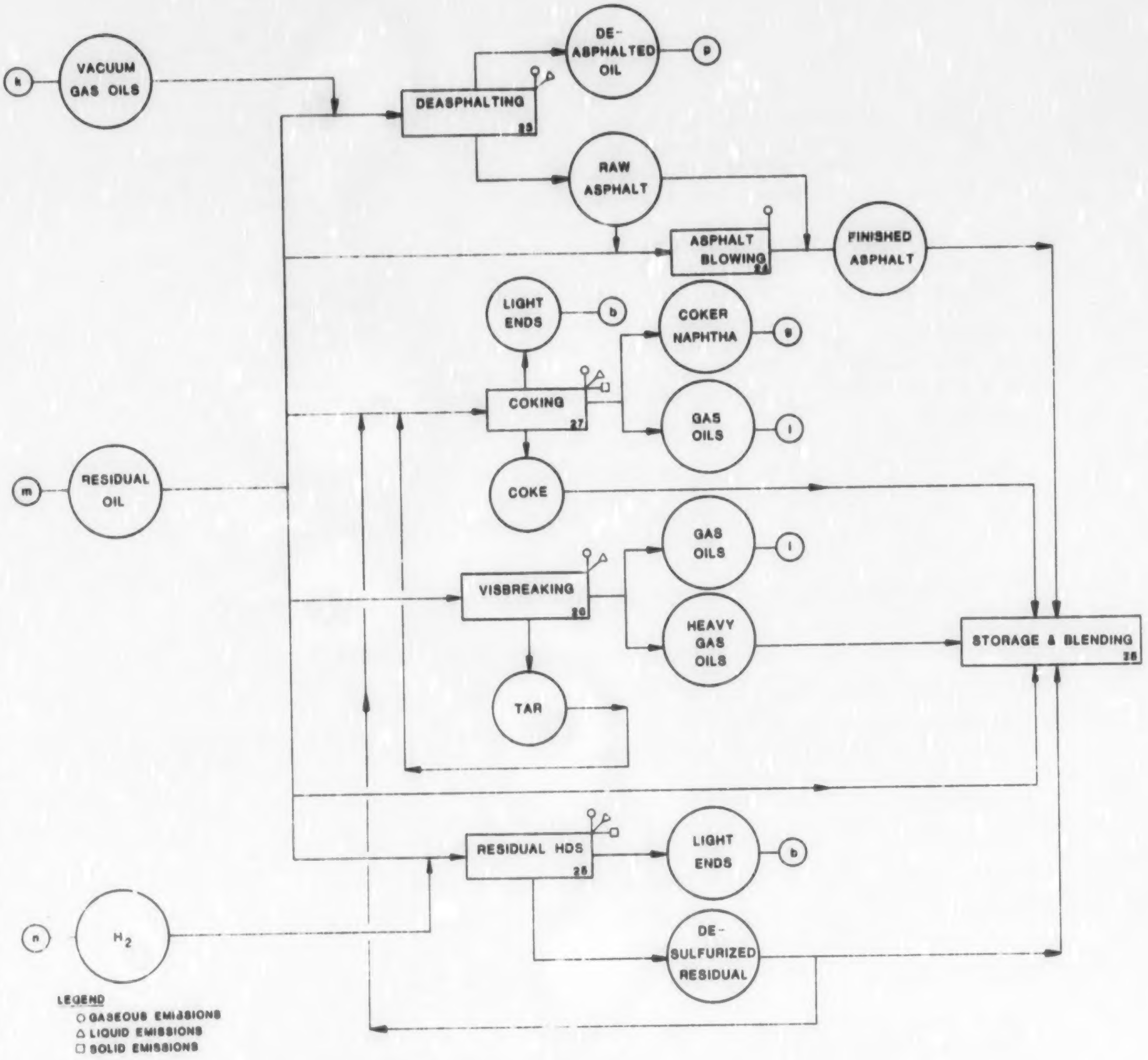
(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle - Columbus Labs., 1974.

Residual Hydrocarbon Processing

There are six process modules in the residual hydrocarbon processing segment. These are shown schematically in Figure 4.

Residuum is the bottoms product of atmospheric or vacuum distillation of crude oil. Residuum can be blended with gas oil or kerosene to a viscosity specification producing a heavy fuel oil (No. 6 Fuel). This fuel is generally used to fire industrial and ship boilers.

Most refiners upgrade the value of residuum by utilizing processes like deasphalting/asphalt blowing, visbreaking, coking, and catalytic hydrodesulfurization.


k
VACUUM GAS OILS
DEASPHALTING
23
DE-ASPHALTED OIL
p
RAW ASPHALT
ASPHALT BLOWING
24
FINISHED ASPHALT
LIGHT ENDS
b
COKER NAPHTHA
g
COKING
27
GAS OILS
i
m
RESIDUAL OIL
COKE
GAS OILS
i
VISBREAKING
26
HEAVY GAS OILS
STORAGE & BLENDING
28
TAR
RESIDUAL HDS
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b
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H_2
DE-SULFURIZED RESIDUAL
LEGEND
○ GASEOUS EMISSIONS
△ LIQUID EMISSIONS
□ SOLID EMISSIONS

FIGURE 4. REFINERY RESIDUAL HYDROCARBON PROCESSING

Deasphalting

1. Function - Deasphalting is applied primarily for the separation of asphaltic materials from heavy oil and residual fractions. This separation (sometimes called decarbonizing) recovers an oil for use as a feed to catalytic processes and also produces a raw asphalt material.

   Deasphalting is usually accomplished by a solvent extraction technique using propane or other light hydrocarbon as the solvent. The vacuum residue and liquid propane are pumped to an extraction tower at controlled ratio and temperature. A separation based on difference in solubility takes place producing a deasphalted oil solution and an asphalt solution. The exit solutions are processed through evaporation and steam stripping to recover the propane from the oil and asphalt products.

2. Input Materials - The feed to a deasphalting unit is usually a vacuum residue. A small amount of propane is required as makeup for that which is consumed in the process. This amounts to about 0.2 m^3/m^3 of feed (1.2 ft^3/bbl).

3. Operating Parameters - The operating conditions for the extraction column are:

   Temperature: 70 to 105°C (160 to 220°F)

   Pressure: 32 to 42 kg/sq cm (450 to 600 psi)

   Typical sizes of equipment range from an operating capacity of 17,000 to 28,000 m^3/day (2700 - 4400 bbl/day).

4. Utilities -

   Electricity: 0 to 20 kWh/m^3 of feed (0 to 3.4 kWh/bbl)

   Steam: 86 to 400 kg/m^3 of feed (30 to 140 lb/bbl)

   Heater Fuel: 127,000 to 220,000 kcal/m^3 of feed (145,000 to 250,000 Btu/bbl)

   Cooling Water: 7250 liters/m^3 of feed (300 gal/bbl).

5. Waste Streams - The two sources of atmospheric emissions from deasphalting operations include the process heater flue gases and fugitive hydrocarbon losses from high pressure equipment. Process heaters will be discussed in a separate module. The miscellaneous hydrocarbon leaks result from equipment with relief valves, pump seals, valve stems, flanges, and compressor seals.

A liquid effluent stream originates from the evaporator jet condensor and trap. The condensed steam is contaminated with hydrocarbons and is sent to the refinery waste water treatment facility.

6. EPA Source Classification Code - None exists

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook". Hydrocarbon Proc. 53 (9), 1974.

Asphalt Blowing

1. Function - The purpose of asphalt blowing is to oxidize those residual oils containing polycyclic aromatic rings. The resulting increase in melting temperature and hardness improves their resistance to weathering. These heavy residual oils, called asphalt, are oxidized by blowing air through a batch heated mixture. The reaction is exothermic and proceeds without additional heat after the asphalt is heated to reaction temperature. The blowing is stopped when the asphalt reaches the desired penetration specification.

2. Input Materials - Feed to the asphalt blowing unit is vacuum resid or raw asphalt from a deasphalting unit.

3. Operating Parameters - Asphalt blowing is an atmospheric pressure operation. The asphalt feed is heated to 260°C to initiate the oxidation reactions.

4. Utilities -

   Heaters: 8,000-16,000 kcal/m^3 feed (5,000-10,000 Btu/bbl) - required to heat asphalt to reaction temperature.

   Electricity: 6 kWh/m^3 feed (1 kWh/bbl) - needed to compress air for the air blowing.

5. Waste Streams - The only emissions are gases to the atmosphere. The quantity is small, since the asphalt previously has been distilled at high temperature. The vent gases are often highly odorous and are usually incinerated. Before incineration of the vent gases became common place, these gases constituted the most objectionable form of air pollution from a refinery.

6. EPA Source Classification Code - None exists.

7. References -

   (1) Nack, H, et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities. EPA 650/2-74/048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

   (2) Sims, Anker V., Field Surveillance and Enforcement Guide for Petroleum Refineries, Final Report, EPA 450/3-74-04, Contract No. 68-02-0645, PB 236 669, Pasadena, CA, Ben Holt Co., 1974.

PROCESS NO. 25

Residual Oil Hydrodesulfurization

1. Function - The catalytic hydrodesulfurization process is used to reduce sulfur, nitrogen and metals concentrations in residuals. There is only limited commercialization of the process since hydrogen consumption is high and catalyst life is relatively short due to high concentrations of contaminants in resids. Many refiners using this process charge an atmospheric resid rather than a vacuum resid.

   The process is the same as for lighter gas oils. The sour resid is mixed with hydrogen, heated in a fired heater and passed through a catalyst bed where the reactions occur in the liquid phase. Some processes utilize a fixed catalyst bed while others have ebullient catalyst beds. Sulfur is converted to H_2S, nitrogen to NH_3 and metals remain on the catalyst. After products from the reactor are cooled, hydrogen and H_2S are flashed off in a series of high and low pressure separators. The hydrogen is recycled and H_2S is recovered for further processing. The oil product is steam stripped to remove residual H_2S. There may also be a fractionation stage to separate out light hydrocarbon fractions. The desulfurized resid is blended to fuel or processed further.

   There is great interest in but limited application of the more severe hydrocracking process, which substatially upgrades the value of residuum.

2. Input Materials - Feed to this unit is usually a high sulfur content atmospheric residue having initial boiling points in the range of 300 to 390°C, although some refiners change vacuum residuals. Also, hydrogen at the rate of 70 to 120 m^3/m^3 of feed (400 to 700 ft^3/bbl) is required.

3. Operating Parameters - The operating conditions for the reactor are:

   Temperature: 340-450°C (650-850°F)

   Pressure: 70 kg/sq cm (1000 psi)

   Catalyst: Cobalt-molybdenum or cobalt-nickel.

4. Utilities -

   Electricity: 6 to 24.0 kWh/m^3 of feed (1 to 4 kWh/bbl)

   Steam: 9 to 71 kg/m^3 (3 to 25 lb/bbl)

   Heater Fuel: 15,700 to 157,000 $kcal/m^3$ (10,000 to 100,000 Btu/bbl)

   Water (cooling): 3570 to 4280 $liters/m^3$ (150 to 180 gal/bbl)

   Water (process): 100 $liters/m^3$ (4.2 gal/bbl)

5. Waste Streams - Atmospheric emissions which result from the operation of this unit originate from the process heaters, periodic catalyst regeneration, and fugitive hydrocarbon leaks. Emissions from the process heaters will be discussed in a separate module. Catalyst regeneration involves burning off deposited coke by passing a steam and air mixture through the bed. The resulting gaseous emissions include significant quantities of carbon monoxide. As with all high pressure refinery equipment, a potential fugitive hydrocarbon emission problem exists. Emissions occur at relief valves, valve stems, flanges, pump seals, and compressor seals.

A liquid waste stream which contains H_2S is removed from the process at the low pressure separator. It is equal in quantity to the amount of process water added. This stream is passed to a sour water stripper for processing. The steam which condenses within the reactor during catalyst regeneration operations is contaminated with H_2S and must be treated in a sour water stripper.

Spent catalyst is either sold to a precious metals reclaimer or disposed of as a solid waste. The catalyst may remain useful for a number of years, so this disposal problem is not significant.

6. EPA Source Classification Code - None exists.

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", Hydrocarbon Proc. 53(9), 1974.

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

Visbreaking

1. Function - The visbreaking process employs thermal cracking of resids under mild conditions to reduce the viscosity or pour point of the charge. The feed to the unit is heated and thermally cracked in the visbreaker furnace. Cracked products are quenched with gas oil and flashed. The vapor overhead is separated into light distillate products while the liquid is processed in a fractionator, usually operating at a vacuum, to recover a heavy distillate. Some refiners blend this distillate to fuel oil while others use it as catalytic cracking feed. The residue or tar from the fractionator is generally used for coker feed.

2. Input Materials - The charge to the visbreaking unit is either a topped crude or vacuum resid. Lighter distillate stocks can be charged.

3. Operating Parameters - The operating conditions of the visbreaker furnace are 450 to 480°C (850 to 890°F) and (4-18 kg/sq cm) 50-250 psig.

4. Utilities -

   Electricity: 10.8 kWh/m^3 of feed (1.8 kWh/bbl)

   Furnace Fuel: 410,000 kcal/m^3 of feed (260,000 Btu/bbl)

   Water (Cooling): 6200 liter/m^3 of feed (260 gals/bbl)

   Steam: 286 kg/m^3 (100 lb/bbl) of feed is produced, with
   57 kg/m^3 (20 lb/bbl) used in the fractionator

5. Waste Streams - Atmospheric emissions which result from the operation of this unit originate from the visbreaker furnace and fugitive hydrocarbon leaks. The emissions from the furnace will be discussed in a separate module. The potential for fugitive hydrocarbon emissions exists within this refinery unit. These emissions may occur at such points as valve stems, flanges, pump seals, and compressor seals.

   A sour water waste stream is withdrawn from the fractionator. It is equal in quantity to the amount of steam used in the column for fractionation. This stream is sent to a sour water stripper for processing.

   No solid wastes are generated from this process.

6. EPA Source Classification Code - None exists

7. References -

(1) "Hydrocarbon Processing Refining Processes Handbook", *Hydrocarbon Proc.* *53* (9), 1974.

(2) Nack, H., et al., *Development of an Approach to Identification of Emerging Technology and Demonstration Opportunties*, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

Coking

1. Function - Coking is a thermal cracking process in which crude oil residue (vacuum residuals) and other decanted oils and tar-pitch products are cracked at high temperature and low pressure into lighter products and petroleum coke. The objective is to produce gas oil and lighter petroleum stocks from the residuum. There are two principal coking processes: the fluid coking process and the delayed coking process. The most widely used is the delayed coking process; very few fluid coking units are now in service.

   In the delayed coking process the charge stock is fed to the bottom section of the fractionator where material lighter than the desired end point of the heavy gas oil is flashed off. The remaining material combines with recycle from the coke drum and is pumped from the bottom of the fractionator to the coking heater where it is rapidly heated. Steam is injected to control velocities in the tubes. The vapor-liquid leaving the coking heater passes to a coke drum where the coke is formed and recovered. Vapors from the top of the drum return to the fractionator where the thermal cracking reaction products are recovered.

2. Input Materials - Feed to a delayed coking unit is usually crude oil residue, decanted oils, or tar-pitch products.

3. Operating Parameters - Operating conditions within the coker tower are:

   Pressure: 1.8 to 2.1 kg/sq cm (25 to 30 psig)

   Temperature: 382°C (750°F)

   A heater heats the bottoms from the fractionator to 480 to 580°C (900 to 1080°F).

4. Utilities -

   Electricity: 9.5 kWh/m^3 of feed (1.5 kWh/bbl)

   Steam: 516 kg/m^3 (180 lbs/bbl) of feed is produced in the process, while 230 kg/m^3 (80 lbs/bbl) is required for stripping.

   Thermal: 475,000 to 630,000 kcal/m^3 of feed (300,000 to 400,000 Btu/bbl)

5. Waste Streams - Atmospheric emissions which result from the operation of this unit originate from the process heater, wind blown coke dust that has been deposited on the equipment, storage containers for the water used in cutting the coke, and fugitive hydrocarbon leaks.

   Emissions from the process heater will be discussed in a separate module. Particulate emissions can result from the coke dust which often covers coking unit equipment. These fine particles will blow with the wind unless the units are washed periodically. Most delayed coking units use water for cutting coke. The water is recycled in this operation and stored in open containers. Since this water contains some sulphur compounds, it may be the source of objectionable odors.

A waste water stream containing H_2S is drawn from the overhead accumulator on the coker tower. This stream is pumped to the sour water stripper for purification before reuse or discharge.

A waste water stream is also produced as a result of steaming the coke drum to remove volatile matter from the coke and using water to cool the drum before opening. Most refiners attempt to remove the oil from this stream and recycle as much as possible. However, much of this water, which contains phenols, H_2S and NH_3 in addition to oil, invariably enters the wastewater treating system.

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Sims, Anker V., Field Surveillance and Enforcement Guide for Petroleum Refineries, Final Report, EPA 450/3-74-042, Contract No. 68-02-0645 PB 236 669, Pasadena, Ca., Ben Holt Co., 1974.

Residual Hydrocarbon Storage and Blending

1. Function - Residuals from crude distillation are stored in heated cone roof tanks. Resid is cut with a lighter hydrocarbon, kerosene or light gas oil, and kept hot to maintain pumpability. The resid can be processed further (coking, visbreaking, hydrodesulfurization) or blended with lighter oils to heavy fuel oil (No. 6, Bunker C) specifications.

2. Input Materials - Residuals from crude distillation.

3. Operating Parameters - The resid is stored at 38-90°C (100-195°)

4. Utilities - Steam is used to heat the residual oil.

5. Waste Streams - Negligible

6. EPA Source Classification - None exists

7. References -

(1) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Auxiliary Processes

There are several processing operations commonly used in the refining industry which are not directly involved in the production of refinery products. These processes are defined as auxiliary processes, and they encompass such operations as wastewater treatment, steam generation, and process heaters.

Products from these operations (clean water, steam, and heat) are common to the majority of process units and are not limited to any one segment. These auxiliary processes contribute to both the liquid and atmospheric emissions from a refinery.

Wastewater Treating

1. Function - The purpose of wastewater treating is to upgrade the quality of effluent water so that it can be safely returned to the environment or recirculated to the refinery. Refinery wastewater typically contains oil, phenols, sulfides, ammonia, and dissolved and suspended solids. Some refinery wastes contain other organic and inorganic chemicals, including some toxic chemicals. The types of treatment processes utilized vary with the types and concentrations of contaminants and with effluent quality requirements.

Wastewater treatment processes can be separated into five general categories: inplant pretreatment, primary treatment, intermediate treatment, secondary treatment and tertiary treatment. Inplant pretreatment processes are applied to individual aqueous streams before those streams are combined with effluent flowing to primary treatment facilities. Some of the most widely used pretreatment processes include sour water stripping, spent caustic oxidation or neutralization, acidic/alkaline waste neutralization, and cooling tower and boiler blowdown treatment.

Primary treatment facilities are usually designed for oil/water separation and for removal of settleable solids from the water. Two widely used designs are the API separator and corrugated plate separators. Both processes utilize gravity separation techniques to remove oil, oily sludge, and grit from incoming wastewater before further treatment.

Intermediate treatment consists of a holding basin of several hours residence time to allow leveling of hydraulic and contaminant concentration surges, and dissolved air flotation units, sedimentation units or filtration units to remove suspended matter from the water.

Secondary treatment processes are biological oxidation processes that degrade the soluble organic contaminants in wastewater. The concentration of contaminants is related to the biological oxygen demand (BOD) of the wastewater. The biological processes utilize microorganisms and oxygen to convert the soluble organic contaminants to CO_2, N_2, and H_2O, thereby reducing the BOD of the wastewater. Several biological processes are in widespread use. Unaerated lagoons are the least complex but require large land areas and low BOD loadings relative to the other processes. Aerated lagoons utilize mechanical mixing and aeration to handle larger BOD loadings. The trickling filter process and its variations, such as the biodisc process, can handle relatively large BOD loadings. The activated sludge process and its variations can treat wastewater with high BOD loadings. The trickling filter and activated sludge processes require a clarification step to remove biological sludge from the effluent.

Tertiary treatment processes are not widely used at the present time but may be required as effluent quality regulations become more restrictive. Processes in limited use or in development include activated carbon adsorption, filtration, ion exchange and reverse osmosis.

The application of the process categories and individual processes as described varies widely in the industry. All refines utilize some combination of primary and intermediate treatment to remove separable oils and solids from waste water. Most are using some form of biological treatment although some may use chemical oxidation processes (oxidation with chlorine, ozone or permanganate) or deep well disposal.

2. Input Materials - Effluent water streams from throughout the refinery are feed streams to the wastewater treating system. Process water, once-through cooling water, wash water, oily storm water, and cooling tower and blowdown are examples.

3. Operating Parameters - Wastewater treatment processes are generally operated at ambient temperatures and pressures.

4. Utilities - Utility requirements vary widely. The biological processes such as aerated lagoons and activated sludge processes are the largest energy consumers.

5. Waste Streams - The atmospheric emissions from wastewater systems consist primarily of hydrocarbons released in the collection system and the API separator. Extensive studies on API separators have shown that in the process of treating aqueous effluents having a temperature of 60°C and containing oil having a 10% TBP of 149°C, 16-17 vol % of the oil vaporizes. Floating an insulating material such as foam glass slabs on the oil has been found to reduce the hydrocarbon emissions to 2 vol % of the oil. Sealing off API separators was found unsatisfactory due to the creation of dangerous explosive spaces. Quantitative studies have shown that the total hydrocarbon emissions from process pumps, drains, and API separators range from 29-570 kg/1000 m^3 capacity-day.

   Solid wastes generated in the waste treatment plant consist of dirt, grit, oily sludges, and clarifier sludges removed in the primary treatment processes, and bacterial sludges removed in the secondary treatment clarifiers. Dirt and grit are disposed of in landfills. Oily sludges are usually landfilled but are sometimes incinerated. Primary treatment clarifier sludges are disposed of in landfills and evaporation ponds. Bacterial sludges are disposed of in incinerators or landfills. The ash generated from burning sludges is normally disposed of in landfills also.

6. EPA Source Classification Code - None exists.

7. References -

(1) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(2) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, Contract No. EQC 319, Austin, Texas, 1974.

Steam Production

1. Function - A steam production unit is used to supply steam to various processes for direct use in the operation, for heating, and to drive steam turbines. From 85 to 285 kilograms of steam are used per cubic meter of crude oil processed in a refinery. Process steam is generated at about 35 kg/sq cm in typical large industrial boilers. Steam of a lower pressure is obtained by reducing the pressure of the 35 kg/sq cm steam.

   Some refinery processes also generate steam in waste heat boilers. The largest process-associated steam generator is the carbon monoxide boiler on the exhaust from the catalytic cracker. The sulfur recovery plant is another process that produces steam as a usable by-product. Most of the process-associated steam production facilities produce a low pressure steam.

2. Input Materials - The feed to the steam production unit is a water stream which is treated to be non-corrosive.

3. Operating Parameters -

   Furnace Temperature: 1200°C

   Boiler Pressure: 35 kg/sq cm

4. Utilities -

   Heaters: 792,500 kcal/m^3 of crude

5. Waste Streams - Atmospheric emissions result from the fired heaters associated with steam production and are directly dependent upon the quality of the fuel burned. For residual oil fired boilers where S equals percent by weight of sulfur in the oil, emissions are as follows:

   Particulates 2.75 kg/m^3 fuel

   Sulfur dioxide 19(S) kg/m^3 fuel

   Sulfur trioxide 0.25(S) kg/m^3 fuel

   Carbon monoxide 0.5 kg/m^3 fuel

   Hydrocarbons 0.35 kg/m^3 fuel

   Nitrogen oxides

   - tangentially fired - 4.8 kg/m^3 fuel
   - horizontally fired - 9.6 kg/m^3 fuel

   Aldehydes - 0.12 kg/m^3 fuel

For gas fired boilers:

Particulates - 290 kg/10^6 m^3 fuel

Sulfur oxides - 9.6 kg/10^6 m^3 fuel
(based on 4600 g sulfur/10^6 m^3 gas)

Carbon monoxide - 270 kg/10^6 m^3 fuel

Hydrocarbons - 48 kg/10^6 m^3 fuel

Nitrogen oxides - 230 kg/10^6 m^3 fuel

S = weight percent sulfur in the fuel

Aqueous effluents are primarily boiler blowdown which does not contain phenols or high BOD compounds. Boiler blowdown is often of high enough quality to be reused in other processes with minimal treatment. Solid wastes include ash from the fuel and sludges from treatment of boiler feed water.

6. EPA Source Classification Code - None exists

7. References -

(1) Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd ed., AP-42, Research Triangle Park, N.C., 1973.

(2) Nack, H., et al., Development of an Approach to Identification of Emerging Technology and Demonstration Opportunities, EPA 650/2-74-048, Columbus, Ohio, Battelle-Columbus Labs., 1974.

(3) Radian Corporation, A Program to Investigate Various Factors in Refinery Siting, Final Report, EQC 319, Austin, Texas, 1974.

Process Heaters

1. Function - Process heaters are used throughout the refinery to supply heat to raise input materials to reaction temperatures or cause them to distill into various fractions. The heaters themselves are not part of the processes and are considered here as a separate process module.

2. Input Materials - Fuels to the heaters are usually either residual fuel oils or refinery gases (mostly methane) produced as a by-product throughout the refinery. Refinery gases produced from various processes are piped to a common system known as plant fuel gas. The plant fuel gas may contain high concentrations of sulfur if the plant fuel gas has not been sent to an amine absorption unit for removal of acid gases. Burning a sour fuel gas would naturally result in excessive sulfur dioxide emissions from the heaters.

   In some areas of the country, most notably Texas and Louisiana, refiners purchase natural gas as a clean fuel source rather than burn residual fuel oils. Although this practice is declining, it still exists and will affect the level of emissions from a refinery.

3. Operating Parameters - Most fired heaters are designed to raise reactants to a maximum temperature of about 500°C. Therefore, the actual firebox temperature will vary but will probably be between 1000 and 1500°C.

4. Utilities - The fuel bill for firing heaters will range between 5 and 10% of the heating value contained in the crude that enters the refinery. This means that for a 10,000 cubic meter per day plant, 500 to 1,000 cubic meters of the crude (as fuel oil equivalent volume) are used to fire the process heaters. In terms of heating values, the fuel requirements are 460,000-920,000 kcal/m^3 crude to the refinery.

5. Waste Streams

   For residual oil fired heaters:

   Particulates 2.75 kg/m^3
   Sulfur dioxide 19(S) kg/m^3 fuel
   Sulfur trioxide 0.25(S) kg/m^3 fuel
   Carbon monoxide 0.5 kg/m^3 fuel
   Hydrocarbons 0.35 kg/m^3 fuel
   tangentially fired - 4.8 kg/m^3 fuel
   horizontally fired - 9.6 kg/m^3 fuel
   Aldehydes - 0.12 kg/m^3 fuel

Where S is the weight percent sulfur in the fuel

For gas fired heaters:

Particulates - 290 kg/10^6 m^3 fuel

Sulfur oxides - 9.6 kg/10^6 m^3 fuel
(based on 4600 g sulfur/10^6 m^3 gas)

Carbon monoxide - 270 kg/10^6 m^3 fuel

Hydrocarbons - 48 kg/10^6 m^3 fuel

Nitrogen oxides - 230 kg/10^6 m^3 fuel

6. EPA Source Classification Code - None exists.

7. References -

(1) Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, 2nd ed., AP-42, Research Triagle Park, N.C., 1973.

(2) "NPRA '74 Panel Views Processes", Hydrocarbon Processing, 54(3), (March 1975).

Pressure Relief and Flare Systems

1. Function - Pressure and flare systems are used to control discharges of vapors and liquids from pressure relieving devices, furnace blowdowns and blowdowns from process units during start-ups, shut-downs or emergencies. Although some pressure relief and safety val es discharge to the atmosphere, environmental and safety considerations generally require the use of a closed blowdown system.

   The blowdown system typically consists of a gathering system for all discharges, a knockout drum to separate vapor and liquid and a flare to insure combustion of vapors vented to the atmosphere. Liquid collecting in the blowdown drum is pumped away to an oil recovery system. Flares are provided with pilots and ignitor systems to insure continuous combustion of hydrocarbons. Steam is usually injected into the combustion zone to promote complete combustion in order to reduce or eliminate smoking.

   Most flares are designed as vertical stacks with the flare tip 20 to 300 feet above the ground. Heat liberation and combustion product dispersion are the primary considerations in determining flare height. Other flares are horizontal designs with the flare tip extending over a burning pit, using steam or water sprays to control smoking. Another type, called a ground flare, utilizes a series of burners at ground level. The burners are designed to induce large quantities of air into the combustion zone to eliminate smoking.

2. Input Stream - All units and equipment subject to start-ups, shut-downs, upsets, emergency venting and purging are connected to a blowdown system.

3. Operating Parameters - A continuous combustion source is required at flares tips to insure combustion of hydrocarbon vapors vented to the atmosphere.

4. Utilities - The steam required for smokeless flaring varies from 0.2 - 0.5 lb Steam/lb Hydrocarbon.

5. Waste Streams - Hydrocarbon emissions from blowdown systems have been estimated to range from 0.34-0.57 kg/m^3 crude (120-200 lbs/10^3 bbl crude).

   Waste water can result if a water quench is used to cool hot streams entering the blowdown drum. The volume of water should be small compared to total effluent and easily handled in the waste water treating system.

6. EPA Source Classification Code - None exists

7. References -

(1) Atmospheric Emissions from Petroleum Refineries, a Guide for Measurement and Control, PHS No. 763, Washington, D.C., Public Health Service (1960).

(2) MSA Research Corporation, Hydrocarbon Pollutant Systems Study, Vol. 1, Stationary Sources, Effects and Control, APTD-1499, PB 219073, Evans City, Pa., MSA Research Corporation (1972).

APPENDIX A

CRUDE OIL ANALYSES

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Table A-1. HYDROCARBONS ISOLATED FROM A REPRESENTATIVE PETROLEUM (PONCA CITY, OKLAHOMA FIELD)

No.	Formula	Compound	Type[a]	Boiling point[b] at 1 atm	Purity of the best sample isolated[c]	Estimated amount in the crude petroleum[d]
				°C.	*Mole per cent*	*Volume per cent*
1.	CH_4	Methane	Normal paraffin	−161.49	f	f
2.	C_2H_6	Ethane	Normal paraffin	−88.63	f	f
3.	C_3H_8	Propane	Normal paraffin	−42.07	f	f
4.	C_4H_{10}	Isobutane	Branched paraffin	−11.73	f	f
5.	C_4H_{10}	*n*-Butane	Normal paraffin	−0.50	f	f
6.	C_5H_{12}	2-Methylbutane	Branched paraffin	27.85	f	f
7.	C_5H_{12}	*n*-Pentane	Normal paraffin	36.07	f	f
8.	C_5H_{10}	Cyclopentane	Cyclopentane	49.26	f	0.05
9.	C_6H_{14}	2,2-Dimethylbutane	Branched paraffin	49.74	f	0.04
10.	C_6H_{14}	2,3-Dimethylbutane	Branched paraffin	57.99	97	0.08
11.	C_6H_{14}	2-Methylpentane	Branched paraffin	60.27	99.97	0.37
12.	C_6H_{14}	3-Methylpentane	Branched paraffin	63.28	99.9	0.35
13.	C_6H_{14}	*n*-Hexane	Normal paraffin	68.74	99.9	1.80
14.	C_6H_{12}	Methylcyclopentane	Cyclopentane	71.81	98.7	0.87
15.	C_7H_{16}	2,2-Dimethylpentane	Branched paraffin	79.20	97	0.02
16.	C_6H_6	Benzene	Benzene	80.10	99.6	0.15
17.	C_7H_{16}	2,4-Dimethylpentane	Branched paraffin	80.50	f	0.08
18.	C_6H_{12}	Cyclohexane	Cyclohexane	80.74	99.9	0.71
19.	C_7H_{14}	1,1-Dimethylcyclopentane	Cyclopentane	87.85	98	0.16
20.	C_7H_{16}	2,3-Dimethylpentane	Branched paraffin	89.78	58[h]	0.15[i]
21.	C_7H_{16}	2-Methylhexane	Branched paraffin	90.05	97	0.73[i]
22.	C_7H_{14}	1,*trans*-3-Dimethylcyclopentane	Cyclopentane	90.77	88	0.87
23.	C_7H_{14}	1,*cis*-3-Dimethylcyclopentane	Cyclopentane	91.72	81[h]	0.21[i]
24.	C_7H_{16}	3-Methylhexane	Branched paraffin	91.85	93	0.51
25.	C_7H_{14}	1,*trans*-2-Dimethylcyclopentane	Cyclopentane	91.87	93	0.49[i]
26.	C_7H_{16}	3-Ethylpentane	Branched paraffin	93.48	98.7[h]	0.06
27.	C_7H_{16}	*n*-Heptane	Normal paraffin	98.43	99.9	2.3
28.	C_7H_{14}	Methylcyclohexane	Cyclohexane	100.93	99.8	1.6
29.	C_7H_{14}	Ethylcyclopentane	Cyclopentane	103.47	98	0.16
30.	C_8H_{16}	1,1,3-Trimethylcyclopentane	Cyclopentane	104.89	98.1	0.30
31.	C_8H_{18}	2,2-Dimethylhexane	Branched paraffin	106.84	50[h]	0.01
32.	C_8H_{18}	2,5-Dimethylhexane	Branched paraffin	109.10	55[h]	0.06[h]

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Table A-1 (Continued). HYDROCARBONS ISOLATED FROM A REPRESENTATIVE PETROLEUM (PONCA CITY, OKLAHOMA FIELD)

No.	Formula	Compound	Type[a]	Boiling point[b] at 1 atm	Purity of the best sample isolated[c]	Estimated amount in the crude petroleum[d]
				°C.	*Mole per cent*	*Volume per cent*
33.	C_8H_{16}	1,*trans*-2,*cis*-4-Trimethylcyclopentane	Cyclopentane	109.29	84^h	0.2
34.	C_8H_{18}	2,4-Dimethylhexane	Branched paraffin	109.43	41^h	0.06^h
35.	C_8H_{18}	2,2,3-Trimethylpentane	Branched paraffin	109.84	1.0^h	0.004^h
36.	C_8H_{16}	1,*trans*-2,*cis*-3-Trimethylcyclopentane	Cyclopentane	110.2	99.6	0.26
37.	C_7H_8	Toluene	Benzene	110.62	98	0.51
38.	C_8H_{18}	3,3-Dimethylhexane	Branched paraffin	111.97	86^h	0.03
39.	C_8H_{18}	2,3,4-Trimethylpentane	Branched paraffin	113.47	17^h	0.005^h
40.	C_8H_{16}	1,1,2-Trimethylcyclopentane	Cyclopentane	113.73	98	0.06
41.	C_8H_{18}	2,3,3-Trimethylpentane	Branched paraffin	114.76	10^h	0.006^h
42.	C_8H_{18}	2,3-Dimethylhexane	Branched paraffin	115.61	65^h	0.07^h
43.	C_8H_{18}	2-Methyl-3-ethylpentane	Branched paraffin	115.65	51^i	0.06^h
44.	C_8H_{16}	1,*cis*-2,*trans*-4-Trimethylcyclopentane	Cyclopentane	116.73	81^i	0.01^i
45.	C_8H_{16}	1,*cis*-2,*trans*-3-Trimethylcyclopentane	Cyclopentane	117.5	90^i	0.07^i
46.	C_8H_{18}	2-Methylheptane	Branched paraffin	117.65	90	0.90^i
47.	C_8H_{18}	4-Methylheptane	Branched paraffin	117.71	34^i	0.20^i
48.	C_8H_{18}	3,4-Dimethylhexane	Branched paraffin	117.72	40^i	0.13^i
49.	C_8H_{18}	3-Methyl-3-ethylpentane	Branched paraffin	118.26	8^i	0.02^i
50.	C_8H_{18}	3-Ethylhexane	Branched paraffin	118.53	43^i	0.09^i
51.	C_7H_{14}	Cycloheptane	Cycloheptane	118.79	90	0.01^i
52.	C_8H_{18}	3-Methylheptane	Branched paraffin	118.92	98^i	0.30^i
53.	C_8H_{16}	1,*trans*-4-Dimethylcyclohexane	Cyclohexane	119.35	75^i	0.25^i
54.	C_8H_{16}	1,1-Dimethylcyclohexane	Cyclohexane	119.54	84^i	0.06^i
55.	C_8H_{16}	1,*cis*-3-Dimethylcyclohexane	Cyclohexane	120.09	84^i	0.63^i
56.	C_8H_{16}	1-Methyl-*trans*-3-ethylcyclopentane	Cyclopentane	120.8	57^i	0.12^i
57.	C_8H_{16}	1-Methyl-*cis*-3-ethylcyclopentane	Cyclopentane	121.4		
58.	C_8H_{16}	1-Methyl-*trans*-2-ethylcyclopentane	Cyclopentane	121.2	74^i	0.14^i
59.	C_8H_{16}	1-Methyl-1-ethylcyclopentane	Cyclopentane	121.52	65^i	0.03^i
60.	C_8H_{16}	1,1-*cis*-3,*trans*-4-tetramethylcyclopentane	Cyclopentane	121.6	83^i	0.04^i
61.	C_8H_{16}	1-*trans*-2-Dimethylcyclohexane	Cyclohexane	123.42	98^i	0.31^i
62.	C_9H_{20}	2,2,5-Trimethylhexane	Branched paraffin	124.08	11^i	0.002^i

Table A-1 (Continued). HYDROCARBONS ISOLATED FROM A REPRESENTATIVE PETROLEUM (PONCA CITY, OKLAHOMA FIELD)

No.	Formula	Compound	Type[a]	Boiling point[b] at 1 atm	Purity of the best sample isolated[c]	Estimated amount in the crude petroleum[d]
				°C	*Mole per cent*	*Volume per cent*
63.	C_8H_{16}	1,*cis*-4-Dimethylcyclohexane	Cyclohexane	124.32	76[i]	0.09[i]
64.	C_8H_{16}	1,*trans*-3-Dimethylcyclohexane	Cyclohexane	124.45	69[i]	0.07[i]
65.	C_8H_{18}	*n*-Octane	Normal paraffin	125.66	99.2	1.9
66.	C_8H_{16}	Isopropylcyclopentane	Cyclopentane	126.42	15[i]	0.01[i]
67.	C_9H_{18}	Tetramethylcyclopentane[e]	Cyclopentane	127.4	90	0.11
68.	C_8H_{16}	1-Methyl-*cis*-2-ethylcyclopentane	Cyclopentane	128.05	52[i]	0.06[i]
69.	C_8H_{16}	1,*cis*-2-Dimethylcyclohexane	Cyclohexane	129.73	48[i]	0.06[i]
70.	C_8H_{16}	*n*-Propylcyclopentane	Cyclopentane	130.95	49[i]	0.06[i]
71.	C_9H_{20}	2,3,5-Trimethylhexane	Branched paraffin	131.34	16[i]	0.08[i]
72.	C_8H_{16}	Ethylcyclohexane	Cyclohexane	131.78	94	0.37[i]
73.	C_9H_{20}	2,6-Dimethylheptane	Branched paraffin	135.21	98.6	0.06
74.	C_8H_{10}	Ethylbenzene	Benzene	136.19	98	0.19
75.	C_9H_{18}	1,1,3-Trimethylcyclohexane	Cyclohexane	136.63	99.9	0.2
76.	C_8H_{10}	*p*-Xylene	Benzene	138.35	99.8	0.10
77.	C_8H_{10}	*m*-Xylene	Benzene	139.10	99.9	0.51
78.	C_9H_{20}	2,3 Dimethylheptane	Branched paraffin	140.5	80	0.05
79.	C_9H_{18}	Trimethylcyclohexane[m]	Cyclohexane	141.2	95	0.2
80.	C_9H_{20}	4-Methyloctane	Branched paraffin	142.48	80	0.1
81.	C_9H_{20}	2-Methyloctane	Branched paraffin	143.26	99.9	0.4
82.	C_9H_{20}	3-Methyloctane	Branched paraffin	144.18	95	0.1
83.	C_8H_{10}	*o*-Xylene	Benzene	144.41	99.7	0.27
84.	C_9H_{18}	Monocycloparaffin[m]	Monocycloparaffin	145.6	99	f
85.	C_9H_{16}	Dicycloparaffin[m]	Dicycloparaffin	146.7	99	f
86.	C_9H_{20}	*n*-Nonane	Normal paraffin	150.80	99.94	1.8
87.	C_9H_{12}	Isopropylbenzene	Benzene	152.39	99.8	0.07[i]
88.	C_9H_{12}	*n*-Propylbenzene	Benzene	159.22	98	0.09[i]
89.	C_9H_{12}	1-Methyl-3-ethylbenzene	Benzene	161.30	99[h]	0.17[i]
90.	C_9H_{12}	1-Methyl-4-ethylbenzene	Benzene	161.99	94[h]	0.09[i]
91.	C_9H_{12}	1,3,5 Trimethylbenzene	Benzene	164.72	99.9	0.12[i]
92.	C_9H_{12}	1-Methyl-2-ethylbenzene	Benzene	165.15	98[h]	0.09[i]
93.	$C_{10}H_{22}$	4-Methylnonane	Branched paraffin	165.7	96	0.1
94.	$C_{10}H_{22}$	2-Methylnonane	Branched paraffin	166.8	99.9	0.3
95.	$C_{10}H_{22}$	3-Methylnonane	Branched paraffin	167.8	98	0.1
96.	$C_{10}H_{14}$	*tert*-Butylbenzene	Benzene	169.12	f	0.01[i]
97.	C_9H_{12}	1,2,4-Trimethylbenzene	Benzene	169.35	99.7	0.51[i]
98.	$C_{10}H_{22}$	*n*-Decane	Normal paraffin	174.12	99.9	1.8
99.	C_9H_{12}	1,2,3-Trimethylbenzene	Benzene	176.08	99.8	0.12
100.	$C_{10}H_{14}$	1-Methyl-3-propylbenzene	Benzene	181.80	f	f
101.	$C_{10}H_{14}$	1,2 Diethylbenzene	Benzene	183.42	f	f
102.	$C_{10}H_{14}$	1-Methyl-2-propylbenzene	Benzene	184.80	f	f
103.	$C_{10}H_{14}$	1,4-Dimethyl-2 ethylbenzene	Benzene	186.91	f	f
104.	$C_{10}H_{18}$	*trans*-Decahydronaphthalene	Dicycloparaffin	187.25	f	f
105.	$C_{10}H_{14}$	1,3-Dimethyl-4-ethylbenzene	Benzene	188.41	f	f
106.	$C_{10}H_{14}$	1,2-Dimethyl-3-ethylbenzene	Benzene	193.91	f	f
107.	$C_{11}H_{24}$	*n*-Undecane	Normal paraffin	195.90	99.97	1.6
108.	$C_{10}H_{14}$	1,2,4,5-Tetramethylbenzene	Benzene	196.80	f	f
109.	$C_{10}H_{14}$	1,2,3,5-Tetramethylbenzene	Benzene	198.00	f	f
110.	$C_{11}H_{20}$	Dicycloparaffin	Dicycloparaffin	202.5	f	f
111.	$C_{11}H_{16}$	Alkylbenzene[m]	Benzene	204.1	95	0.09
112.	$C_{10}H_{14}$	1,2,3,4-Tetramethylbenzene	Benzene	205.04	99.9	0.2

Table A-1 (Continued). HYDROCARBONS ISOLATED FROM A REPRESENTATIVE PETROLEUM (PONCA CITY, OKLAHOMA FIELD)

No.	Formula	Compound	Type[a]	Boiling point[b] at 1 atm.	Purity of the best sample isolated[c]	Estimated amount in the crude petroleum[d]
				°C.	*Mole per cent*	*Volume per cent*
113.	$C_{11}H_{16}$	1,3-Dimethyl-4-n-propylbenzene[n]	Benzene	208.6	96	0.03
114.	$C_{10}H_{12}$	1,2,3,4-Tetrahydronaphthalene	Tetrahydronaphthalene	207.57	98.5	0.03
115.	$C_{11}H_{16}$	1,2-Dimethyl-4-n-propylbenzene[n]	Benzene	208.5	99	0.03
116.	$C_{11}H_{16}$	Trimethylethylbenzene[m]	Benzene	212.3	97	0.04
117.	$C_{12}H_{26}$	n-Dodecane	Normal paraffin	216.28	99.9	1.4
118.	$C_{10}H_{8}$	Naphthalene	Naphthalene	217.96	99.9	0.06
119.	$C_{11}H_{14}$	Aromatic-cycloparaffin[m]	Aromatic-cycloparaffin	220.7	97	0.04
120.	$C_{11}H_{14}$	6-Methyl-[1,2,3,4-tetrahydronaphthalene]	Tetrahydronaphthalene	229.03	99.5	0.09
121.	$C_{11}H_{14}$	5-Methyl-[1,2,3,4-tetrahydronaphthalene]	Tetrahydronaphthalene	234.35	99.7	0.08
122.	$C_{13}H_{28}$	n-Tridecane	Normal paraffin	235.44	98	1.2
123.	$C_{11}H_{10}$	2-Methylnaphthalene	Naphthalene	241.05	99.9	0.2
124.	$C_{11}H_{10}$	1-Methylnaphthalene	Naphthalene	244.64	99.7	0.1
125.	$C_{14}H_{30}$	n-Tetradecane	Normal paraffin	253.57	98.5[h]	1.0
126.	$C_{12}H_{12}$	2,6-Dimethylnaphthalene	Naphthalene	262	f	f
127.	$C_{15}H_{32}$	n-Pentadecane	Normal paraffin	270.63	98.5[h]	0.8
128.	$C_{13}H_{14}$	Trimethylnaphthalene[n]	Naphthalene	285	f	f
129.	$C_{16}H_{34}$	n-Hexadecane	Normal paraffin	286.79	98[k]	0.7
130.	$C_{17}H_{36}$	n-Heptadecane	Normal paraffin	301.82	97[k]	0.6

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[a] The compounds are classified according to the following types: normal paraffin; branched paraffin; cyclopentane (cyclopentane and its alkyl derivatives); cyclohexane (cyclohexane and its alkyl derivatives); benzene (benzene and its alkyl derivatives); naphthalene (naphthalene and its alkyl derivatives); tetrahydronaphthalene (tetrahydronaphthalene and its alkyl derivatives); aromatic-cycloparaffin (mixed type); dicycloparaffin. "Monocycloparaffin" indicates either the "cyclopentane" or the "cyclohexane" type.

[b] This is the value for the pure compound, as taken from the Tables and files of the API Research Project 44 (1), and is not necessarily the temperature at which the compound appears in the distillation of the appropriate fraction of petroleum.

[c] Where the amount of the best sample isolated was sufficient, and the sample was crystallizable, the purity has been calculated from the value of the freezing point previously reported and the present best values of the freezing point for zero impurity and cryoscopic constants from the API Research Projects 44 and 6. Where not evaluated cryoscopically, the purity has been evaluated from the physical properties or spectrographic measurements or both.

[d] The values for the amount in the crude petroleum are rounded estimates subject to revision as new data become available from the work in progress.

[e] The numbers in this column refer to the published papers of the American Petroleum Institute Research Project 6, a list of which is given in Appendix I.

[f] Not determined.

[g] Unpublished.

[h] Determined spectrographically from measurements made in the Socony-Vacuum Laboratories, Paulsboro, N. J.

[i] Determined spectrographically from measurements made in the laboratories of the Humble Oil and Refining Company, Houston, Texas.

[j] Determined spectrographically from measurements made in the following laboratories: Humble Oil and Refining Company, Baytown, Texas; Socony-Vacuum Laboratories, Paulsboro, N. J.; Standard Oil Development Company, Elizabeth, N. J.; Sun Oil Company, Norwood, Pa.

[k] Purification of these samples was not carried to completion because, for purposes of identification, much purer samples were available from other sources.

[m] Identity not yet established.

[n] Tentative; identification not complete.

Item No.	State Field (Formation, age)[1]	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
	Alabama														
1	Citronelle (Rodessa, L. Cre.)	43.6	0.38	40	6.7	34.2	65.6	20.7	47.2	9.6	38.2	17.1	36.6-28.4	16.7	16.5
	Alaska														
2	Swanson River (Hemlock, Eoc.)	29.7	0.16	61	22.3	27.4	56.7	9.1	43.1	15.4	34.6	16.7	31.1-22.5	31.4	7.8
	Arkansas														
3	Magnolia (Reynolds-Smackover, Jur.)	38.4	0.90	38	6.7	32.2	59.2	10.5	43.6	22.2	35.2	11.4	31.5-25.9	20.5	17.3
4	Midway (Smackover, Jur.)	36.6	1.38	42	11.3	30.8	62.6	10.0	43.4	16.0	35.2	16.2	31.0-24.2	24.9	13.6
5	Schuler (Jones & Cotton Valley, Jur.)	32.8	1.55	52	12.0	26.4	60.2	9.5	43.2	15.5	35.8	16.3	31.3-24.5	31.7	13.2
6	Smackover (U. Cre.)	22.5	2.10	220	8.5	11.2	49.0	...	...	20.6	33.0	20.2	27.9-21.3	47.0	12.3
	California														
7	Belgian Anticline (Oceanic, Olig.)	35.0	0.50	40	8.3	35.5	56.4	5.5	41.1	21.2	35.4	15.5	31.3-22.5	22.2	11.9
8	Belridge, South (Tulare, Plio.-Pleist.)	15.0	0.23	2,440	11.3	2.1	44.3	...	...	17.2	30.4	29.6	24.3-12.0	49.4	7.1
9	Brea Olinda (Mio.)	24.0	0.75	135	14.2	19.4	51.3	...	...	20.7	33.8	20.4	28.9-16.8	37.7	7.8
10	Buena Vista (27-B Basal Etchegoin, Plio.)	30.6	0.59	46	12.1	33.9	54.2	...	...	21.2	32.5	15.0	27.1-18.4	28.0	11.0
11	Castaic Junction (Zone 10, Mohnian, Mio.)	19.0	3.40	1,230	9.4	17.1	57.4	...	...	16.0	33.2	13.1	27.9-19.2	53.3	5.6
12	Cat Canyon, West (Los Flores, Mio.)	17.5	5.07	3,000	13.8	13.3	58.9	2.6	42.1	14.0	33.2	13.5	27.5-20.0	55.7	4.8
13	Coalinga, East (Main Gatchell, Eoc.)	28.8	0.31	67	9.9	23.2	52.3	...	...	26.0	34.4	21.6	28.2-22.5	28.4	11.6
14	Coalinga Nose (Gatchell, Eoc.)	31.5	0.25	48	8.0	25.1	53.0	...	...	32.2	33.8	16.2	28.4-22.5	24.8	13.5
15	Coalinga, West (Temblor, Mio.)	20.2	0.55	195	10.9	6.9	45.2	...	...	20.5	29.7	28.9	24.5-14.4	36.5	10.3
16	Coles Levee, North (Mio.)	34.0	0.39	43	10.3	35.0	56.2	...	...	21.0	35.0	16.3	29.7-19.7	25.3	11.7
17	Coyote, West (Emery, Repetto, Plio.)	32.3	0.82	50	11.6	29.9	53.7	4.6	40.9	18.8	34.4	16.9	30.2-21.5	29.2	11.4
18	Cuyama, South (Dibblee, Mio.)	32.5	0.42	49	6.5	30.1	56.4	4.6	40.0	17.9	34.4	16.6	29.7-21.8	27.6	10.4
19	Cymric (McKittrick Group, Tulare, Plio.-Pleist.)	13.7	1.16	6,000	11.0	...	...	1.8	44.7	11.2	31.0	26.6	25.4-15.0	50.4	6.8
20	Dominguez (Plio.-Mio.)	29.9	0.40	60	13.2	26.4	58.7	5.5	40.7	19.5	34.6	17.9	29.9-21.5	29.9	11.0
21	Edison (Chanac, Jur.)	35.2	0.20	115	11.2	20.6	51.8	...	...	21.5	32.7	19.5	28.6-19.5	38.0	10.1
22	Elk Hills (Shallow, U. Plio.)	22.8	0.66	186	4.6	11.1	40.9	...	...	26.7	31.7	22.0	25.7-17.8	37.4	11.1
23	Fruitvale (Chanac, Plio.-Mio.)	17.5	0.93	1,750	9.8	0.7	43.4	...	...	19.0	30.8	25.4	26.6-18.1	54.4	11.3
24	Gosford, East (Middle & Lower-Stevens, Mio.)	34.0	0.57	51	8.0	34.6	57.7	...	...	19.6	35.6	16.8	30.0-20.2	25.0	10.0
25	Greeley (Rio Bravo-Vedder, Mio.)	37.2	0.31	41	11.3	37.3	57.4	5.1	40.2	18.5	34.6	16.5	30.6-22.0	19.9	12.0
26	Guijarral Hills (Leda, Olig.)	36.8	0.63	40	10.9	37.7	58.4	4.4	40.6	20.3	35.0	16.1	30.8-22.6	20.7	12.0
27	Honor Rancho (Wayside, U. Mio.)	37.6	0.40	37	8.0	37.5	54.9	...	...	27.0	35.0	14.7	30.6-23.1	17.8	13.9
28	Huntington Beach (S. Main area, Mio.)	22.6	1.57	210	6.2	20.0	52.3	...	...	18.6	33.4	17.9	28.4-17.0	43.1	7.9
29	Inglewood (Vickers, L. Mio.)	18.1	2.50	680	12.3	11.7	48.5	...	...	19.3	31.9	17.2	26.4-17.9	51.6	7.6
30	Kern Front (Chanac, Plio.-Mio.)	14.8	0.85	5,100	10.0	...	...	...	...	13.7	31.0	29.1	25.4-15.0	55.8	8.9
31	Kern River (Kern River, Plio.-Pleist.)	12.6	1.19	6,000	10.0	...	...	...	...	9.6	29.9	23.3	24.5-15.1	65.7	8.2
32	Kettleman North Dome (Temblor, Mio.)	34.0	0.40	44	12.3	33.5	54.2	6.1	40.6	20.6	34.8	20.5	30.6-19.7	19.1	11.7
33	Long Beach (Alamitos, Repetto, P[illegible])	22.6	1.20	208	6.3	13.7	51.3	4.6	40.0	17.9	34.2	21.1	29.1-17.8	38.7	8.7
34	Midway-Sunset (Plio.-Pleist.)	21.6	0.89	210	5.7	14.8	51.1	...	...	23.5	32.1	20.7	25.9-16.0	40.6	9.2
35	Montalvo, West (Colonia, Sespe, Olig.)	17.3	4.10	7,648	7.9	14.6	55.7	2.7	40.8	12.6	34.8	19.2	28.2-19.4	50.0	2.8
36	Mount Poso (Vedders, L. Mio.)	16.0	0.68	1,900	10.9	...	...	...	...	13.6	30.6	33.8	26.4 15.3	52.0	10.3
37	Newhall-Potrero (Modelo, Mio.)	32.7	0.36	46	11.4	33.9	57.2	4.5	40.4	16.8	34.4	14.9	30.4-22.1	28.4	10.1
38	Oxnard (McInnes, Sespe, Olig.)	25.7	1.72	95	7.6	20.3	56.2	3.8	41.1	17.3	35.0	19.6	29.3-19.0	36.0	7.1
39	Richfield (Kraemer, Mio.)	22.6	1.86	230	11.5	18.9	52.0	...	...	20.7	33.4	17.3	28.8-18.9	42.9	7.8
40	Rincon (Plio.)	26.2	1.40	80	11.0	26.3	56.7	3.8	41.1	16.4	34.8	18.4	30.6-20.3	34.1	8.5
41	Rio Bravo (Rio Bravo, Mio.)	38.6	0.35	38	7.1	40.3	56.9	4.6	40.2	19.2	35.2	14.9	31.3-24.2	18.6	15.0
42	Russell Ranch (Dibblee, Vaqueros, Mio.)	35.2	0.35	43	13.1	32.9	58.4	...	...	24.7	34.6	17.4	28.0-22.8	23.0	11.4
43	San Ardo (Lombardi, Mio.)	11.1	2.25	6,000	4.6	...	...	...	...	11.7	30.2	14.7	25.6-17.3	72.0	6.8
44	San Emidio Nose (Reef Ridge, Mio.)	29.7	0.83	59	6.8	27.3	56.2	4.4	41.3	18.2	35.0	19.1	29.9-20.5	30.3	10.6
45	Sansinena (Mio.)	28.6	0.87	63	9.8	28.1	52.5	...	...	22.5	34.0	18.3	29.5-20.0	30.9	10.0
46	Santa Fe Springs (Buckbee, Plio.)	32.8	0.33	47	10.1	28.5	52.0	6.3	40.6	22.7	34.6	17.5	30.4-23.1	23.2	12.0
47	Santa Maria Valley (Monterey, Mio.)	14.7	4.90	6,000	14.8	11.3	53.0	...	...	15.3	32.5	11.3	25.4-18.2	61.3	4.8
48	Seal Beach (McGrath, Mio.)	31.7	0.55	52	10.8	29.0	55.9	4.9	41.5	19.5	34.8	18.1	30.6-20.7	28.1	11.3
49	South Mountain (Sespe, Olig.)	23.3	2.79	220	13.5	20.4	58.2	3.4	41.1	15.5	33.6	14.1	28.8-20.2	46.0	7.5
50	Tejon, North (Zemorrian, 1-R, Mio.)	40.0	0.16	35	9.8	47.8	54.2	5.7	39.6	19.4	33.4	15.5	28.9-21.5	8.9	12.0
51	Torrance (Del Amo, Mio.)	23.8	1.84	100	13.2	17.9	52.5	...	...	21.0	34.0	18.4	28.4-20.0	41.9	9.4
52	Ventura (Pico-Repetto, Plio.)	31.3	0.94	56	13.5	30.0	57.4	4.1	40.4	16.3	34.6	16.3	31.1-20.7	31.5	10.9
53	Wheeler Ridge (Eoc.)	37.0	0.29	38	7.8	34.9	55.4	...	...	28.1	34.4	17.2	29.9-23.5	17.3	15.0
54	Wilmington (Harbor area, Terminal, Mio.)	22.3	1.33	210	6.3	16.7	56.5	...	...	19.4	33.0	20.7	27.1-17.1	42.1	8.7
	Colorado														
55	Adena (Dakota "J", Cre.)	44.7	<0.10	36	2.9	37.1	60.5	18.5	42.8	13.8	37.6	12.5	36.8-31.1	15.9	21.8
56	Rangely (Weber, Penn.)	34.8	0.86	48	7.6	26.1	59.5	10.3	41.5	15.3	34.6	20.3	32.1-24.5	26.5	15.6
57	Wilson Creek (Morrison, Jur.)	48.1	0.12	33	4.8	49.9	64.8	11.0	43.6	15.0	37.4	12.3	34.6-28.4	10.8	20.8

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Table A-2(Continued). PROPERTIES OF UNITED STATES CRUDE OILS

Item No.	*State* Field (Formation, age)¹	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
	Illinois														
58	Clay City (Miss.)	36.6	0.19	43	8.2	32.8	59.2	10.1	42.3	14.0	34.2	17.8	30.2-21.5	21.6	18.9
59	Dale (Aux Vases, Miss.)	36.4	0.15	49	4.3	29.1	58.2	10.5	42.8	13.7	36.2	15.9	33.2-25.9	30.0	20.3
60	Lawrence (Bridgeport, Penn.)	35.6	0.21	46	8.4	29.8	60.0	9.5	41.9	13.7	35.6	16.3	32.8-24.2	28.3	15.9
61	Loudon (Bethel, Miss.)	36.2	0.22	45	7.6	30.2	59.5	10.2	42.6	14.2	36.4	15.7	33.6-25.9	29.0	16.4
62	New Harmony (McClosky, Miss.)	36.0	0.23	45	7.7	31.2	58.4	10.3	41.9	13.4	35.8	36.7	32.3-24.5	25.4	14.8
63	Robinson-Stoy (Robinson, Penn.)	37.4	0.20	44	9.0	32.6	60.5	10.3	41.9	13.3	35.8	16.3	32.8-25.6	25.4	16.8
64	Salem (Aux Vases, Miss.)	37.2	0.17	43	11.4	32.5	60.7	9.7	42.1	14.5	35.4	15.9	33.2-24.9	25.3	16.0
	Indiana														
65	Griffin (Cypress, Miss.)	35.2	0.20	47	11.2	30.9	59.7	10.5	42.6	14.1	42.3	16.7	33.6-24.9	27.5	14.8
	Kansas														
66	Bemis-Shutts (U. Arbuckle, Ord.)	31.6	0.57	52	11.9	28.3	60.5	9.6	42.3	14.2	36.6	16.5	32.8-25.6	29.5	14.1
67	Chase-Silica (Kansas City, Penn.)	38.8	0.44	42	6.7	38.7	60.0	11.7	43.4	13.5	36.8	13.7	33.4-25.4	21.3	14.1
68	El Dorado (Admire, Perm.)	36.8	0.18	43	8.3	32.1	59.5	13.3	43.4	16.6	36.0	17.8	32.5-21.9	19.5	12.9
69	Hall-Gurney (Kansas City, Penn.)	39.4	0.34	43	8.6	36.2	60.0	11.0	43.2	15.3	37.0	14.9	33.6-26.3	21.1	15.7
70	Kraft-Prusa (Pre-Cambrian)	43.0	0.27	38	12.7	40.9	64.5	11.8	44.1	14.9	37.4	13.7	33.8-26.1	17.6	15.9
71	Seely-Wick (Bartlesville, Penn.)	41.1	0.23	38	9.6	35.3	61.8	10.5	42.8	14.3	36.4	16.3	33.4-26.8	20.8	17.9
72	Spivy-Grabs (Miss.)	23.5	0.93	84	14.3	22.8	56.4	9.1	41.7	11.8	34.6	18.5	31.3-23.1	36.7	1.6
73	Trapp (Arbuckle, Ord.)	39.2	0.41	41	11.2	34.3	62.9	9.9	42.8	15.8	37.2	15.2	33.6-26.3	23.4	16.5
	Louisiana														
74	Avery Island (U. Mio.)	34.4	0.12	46	3.1	18.2	55.4	4.6	42.3	29.0	34.8	25.9	31.1-26.3	20.3	20.5
75	Bateman Lake (9900′, U. Mio.)	38.2	0.15	41	3.3	22.5	53.2	31.6	42.1	14.0	35.8	16.2	34.6-26.4	15.2	20.7
76	Bay de Chene (Mio.)	33.6	0.27	52	5.0	19.3	55.7	11.5	41.3	20.9	35.2	22.1	31.5-24.5	25.2	18.1
77	Bay Marchand (3000′ Mio.)	20.2	0.46	270	7.5	2.5	45.8			22.2	30.8	38.8	25.2-16.2	34.8	11.7
78	Bay St. Elaine (U. Mio.)	33.6	0.39	49	4.3	21.2	53.0	6.7	41.3	25.4	35.6	21.5	31.7-25.6	24.5	19.2
79	Bayou Sale (Morin, Mio.)	36.2	0.16	44	2.2	18.5	53.5	15.5	41.9	25.4	36.2	20.4	33.6-27.7	18.1	21.0
80	Black Bay, West (7300′, Mio.)	30.0	0.27	57	6.3	15.2	54.2	5.5	42.1	24.8	35.0	21.7	30.6-23.7	29.8	15.6
81	Black Bay, West (8050′, Mio.)	23.0	0.36	140	9.0	6.3	48.5			25.0	32.8	35.1	26.8-17.5	31.9	14.1
82	Black Bay, West (8300′, Mio.)	30.6	0.26	58	7.1	16.2	55.9	4.9	43.0	23.9	35.4	21.7	30.6-22.6	30.7	15.7
83	Black Bay, West (8650′, Mio.)	34.4	0.18	45	5.6	19.8	54.2	13.8	42.1	21.7	35.8	20.2	32.8-25.0	22.8	18.4
84	Black Bay, West (9100′, Mio.)	35.2	0.17	43	5.1	21.7	55.2	13.0	42.1	20.3	36.2	20.5	33.2-25.4	22.4	18.6
85	Black Bay, West (9200′, Mio.)	34.4	0.19	46	4.6	19.4	53.5	12.5	42.1	21.9	36.4	20.2	33.4-26.1	24.5	19.0
86	Caddo (Annona Chalk, U. Cre.)	36.8	0.37	44	6.0	27.0	54.7	12.4	41.7	20.4	36.8	18.5	34.6-28.9	21.5	20.7
87	Caillou Island (No. 70, Mio.)	35.4	0.23	45	6.3	28.1	56.7	12.1	41.9	16.5	35.4	19.4	32.7-24.0	23.1	17.1
88	Cameron, West (Block 45, U. Mio.)	39.2	<0.10	41	2.3	18.2	51.6	21.9	42.6	39.6	37.4	12.9	34.8-30.0	6.7	20.7
89	Cote Blanche Bay, West (U. Mio.)	33.6	0.16	49	3.9	16.6	51.1	5.5	41.5	30.8	35.4	23.7	31.9-26.1	21.9	20.2
90	Cotton Valley (Bodcaw, Jur.)	40.6	<0.10	46	0.6	19.1	60.0	15.8	44.7	15.7	38.6	22.3	37.2-34.4	25.9	31.9
91	Cox Bay (Mio.)	31.9	0.38	56	5.7	20.4	58.2	4.9	43.2	24.1	35.6	22.6	30.8-23.5	27.2	15.9
92	Delhi (Tuscaloosa, U. Cre.)	41.7	<0.10	39	5.1	33.1	61.0	10.4	44.3	18.3	37.6	19.0	35.0-27.9	16.8	19.0
93	Delta Farms (Mio.)	35.6	0.26	44	4.9	26.0	55.4	14.1	41.7	18.5	35.2	19.5	32.1-25.9	20.6	17.8
94	Duck Lake (U. Mio.)	36.4	0.14	44	2.0	11.7	52.0	13.1	41.5	39.4	36.8	21.3	35.0-27.1	14.3	22.1
95	Erath (Mio.)	31.0	0.20	54	2.5	15.0	54.4			36.6	33.6	27.7	29.5-24.0	20.5	19.0
96	Eugene Island (Block 32, 7500′, Mio.)	39.2	<0.10	39	1.3	13.0	52.0	40.4	42.1	10.5	38.6	18.3	35.4-29.7	8.4	24.2
97	Eugene Island (Block 126, Mio.)	36.2	0.19	52	2.9	17.6	57.9	20.5	42.8	12.6	35.4	23.5	34.6-27.5	25.0	21.1
98	Eugene Island (Block 188, 9080′, Mio.)	27.1	0.35	91	4.7	4.1	45.8			32.7	33.8	35.0	28.8-22.3	26.9	17.9
99	Garden Island Bay (Mio.)	34.8	0.22	49	7.4	23.6	55.4	5.3	42.3	24.0	36.4	23.8	32.7-24.3	20.9	16.2
100	Golden Meadow (Mio.)	37.8	0.18	44	1.9	19.1	54.4	23.0	42.6	17.7	36.8	22.0	36.0-28.6	17.4	22.3
101	Grand Bay (Mio.)	35.0	0.31	48	3.0	20.5	55.2	12.5	41.1	22.1	35.8	22.1	33.6-27.1	22.6	19.8
102	Grand Isle (Block 16, B-1, Seg. E, Plio.)	36.4	0.18	40	3.7	25.8	54.7	15.0	41.7	19.9	35.8	19.0	32.3-25.4	18.6	18.9
103	Grand Isle (Block 18, B-2, Plio.)	34.6	0.22	46	5.1	21.0	53.2	6.9	43.0	31.1	36.2	22.1	31.3-24.0	17.6	17.9
104	Grand Isle (Block 47, Plio.-Mio.)	33.6	0.23	56	5.7	18.0	56.2	12.7	41.9	20.9	35.8	22.7	32.1-25.0	24.6	18.2
105	Hackberry, West (U. Mio.)	31.3	0.29	45	5.2	22.0	49.5	7.0	40.0	27.5	32.1	23.0	28.4-22.8	20.2	18.2
106	Krotz Springs (Frio, Olig.)	54.9	<0.10	34	Nil	67.0	62.6	10.7	43.0	10.6	36.4	2.1	33.8-32.5	5.7	22.8
107	Lafitte (Mio.)	36.2	0.30	45	3.3	20.8	55.2	13.8	43.4	22.4	37.2	21.4	34.4-27.5	21.3	20.3
108	Lake Barre (R-1, Mio.)	40.4	0.14	39	2.2	36.2	57.2	14.4	42.8	16.3	36.0	18.3	33.4-25.9	14.0	20.3
109	Lake Pelto (U. Mio.)	34.6	0.21	45	3.9	17.9	53.7	7.5	42.1	33.1	36.2	21.1	32.7-25.6	19.3	18.9
110	Lake Salvador (Mio.)	35.4	0.14	47	5.6	14.6	52.5	13.8	42.8	25.3	36.8	50.7	34.2-25.7	14.3	18.4
111	Lake Washington (Mio.)	28.2	0.37	82	9.2	20.0	57.7	3.7	42.1	19.3	33.8	22.5	28.2-20.2	32.5	12.2
112	Leeville (U. Mio.)	35.4	0.20	45	4.7	26.8	52.4	15.7	42.3	16.8	36.2	18.8	32.3-24.0	21.7	18.4
113	Little Lake (Faggerella 2, Mio.)	32.1	0.27	58	5.3	18.3	55.9	12.2	41.9	18.8	34.8	23.8	31.9-24.7	26.1	16.7
114	Little Lake (Faggerella 4, Mio.)	32.5	0.26	61	7.1	18.2	56.3	13.1	42.1	17.7	35.2	22.6	31.9-24.3	26.7	14.8
115	Little Lake (Textularia Panamensis 1, Mio.)	31.7	0.27	59	5.3	17.8	54.0	13.2	41.5	18.9	34.6	22.1	30.4-24.5	26.7	16.4
116	Little Lake (Textularia Panamensis 2, Mio.)	36.2	0.15	46	3.9	17.3	55.4	13.7	43.6	26.6	37.4	34.6	34.8-27.7	17.6	20.2
117	Little Lake (Textularia Panamensis 6, Mio.)	46.3	<0.10	34	4.8	45.9	59.7	24.8	43.6	10.8	37.0	12.8	35.6-27.0	5.1	19.5

Table A-2 (Continued). PROPERTIES OF UNITED STATES CRUDE OILS

Item No.	*State* Field (Formation, age)[1]	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
118	Little Lake, South (Textularia Panamensis 1 "D", Mio.)	34.8	0.26	40	9.9	23.6	55.2	13.0	44.1	19.0	36.8	23.9	32.5-23.5	20.1	16.7
119	Main Pass (Block 69, Mio.)	30.6	0.25	61	6.2	16.0	53.2	4.6	41.1	25.4	35.2	23.6	31.7-24.7	29.6	17.0
120	Paradis (Paradis, Mio.)	36.0	0.23	41	4.4	29.4	53.0	7.2	42.6	26.1	36.0	18.2	31.7-24.5	18.9	19.0
121	Quarantine Bay (Mio.)	31.9	0.27	52	6.1	19.6	54.0	5.6	41.5	26.0	35.6	21.4	31.3-23.3	26.8	17.1
122	Romere Pass (Mio.)	37.4	0.30	44	7.1	26.4	60.0	11.0	42.8	19.3	37.2	19.4	34.0-27.5	22.9	17.9
123	Ship Shoal (Block 154, Mio.)	29.1	0.36	78	3.5	8.7	51.1	5.5	41.9	26.6	34.8	30.1	30.6-23.0	27.7	17.8
124	South Pass (Block 24, Mio.)	33.3	0.26	51	5.2	18.7	54.9	5.1	40.6	25.4	34.6	23.2	31.0-23.5	26.3	17.3
125	Timbalier Bay (Mio.)	34.4	0.33	43	7.7	31.6	57.4	5.5	42.6	19.9	34.2	19.6	30.2-21.1	21.8	14.5
126	Venice (Mio.)	37.6	0.24	41	6.0	30.4	55.9	13.3	42.6	20.2	36.2	16.7	33.0-26.6	19.2	18.1
127	Weeks Island (Mio.)	33.2	0.19	51	4.8	20.1	54.9	4.7	42.8	26.6	35.4	24.1	31.5-24.7	22.4	18.7
128	West Bay (Mio.)	32.1	0.27	54	6.8	17.2	53.7	5.3	42.6	27.5	36.4	21.9	33.7-24.7	27.3	17.9
129	West Delta (Block 30, Mio.)	27.0	0.32	92	5.7	9.5	50.9	4.7	40.0	24.4	33.5	28.5	29.1-22.1	32.7	16.2
130	West Delta (Block 53, KE, U. Mio.)	33.3	0.43	66	6.7	17.6	56.7	11.4	42.8	18.6	35.8	22.7	32.8-23.7	28.2	16.4
131	West Delta (Block 83, KE, U. Mio.)	35.0	0.37	48	6.7	22.1	58.7	12.6	43.4	18.0	36.6	18.9	32.7-26.3	26.8	17.3
	Michigan														
132	Albion (Trenton-Black River, Ord.)	41.9	0.10	44	3.5	28.9	63.1	17.3	45.8	9.4	36.6	13.3	35.0-28.9	25.7	20.8
	Mississippi														
133	Baxterville (L. Tuscaloosa, U. Cre.)	17.1	2.71	1,480	16.6	5.2	55.4	2.1	40.4	14.4	33.2	24.3	29.3-19.7	52.8	7.0
134	Brookhaven (L. Tuscaloosa, L. Cre.)	35.0	0.43	50	5.5	25.7	60.0	10.8	41.9	16.7	32.7	17.8	32.8-26.3	28.0	15.1
135	Bryan (Rodessa, L. Cre.)	37.2	1.47	47	6.3	32.3	67.0	15.3	47.2	10.0	36.4	13.7	34.0-27.1	27.5	10.7
136	Heidelberg (U. Tuscaloosa, U. Cre.)	23.3	3.75	370	10.0	19.2	64.5	6.3	43.2	11.1	35.0	16.1	30.6-20.2	45.4	5.0
137	Little Creek (L. Tuscaloosa, U. Cre.)	38.0	0.16	42	5.4	33.4	56.9	10.9	42.8	16.3	36.4	17.1	33.4-27.9	21.6	17.6
138	Raleigh (Hosston, L. Cre.)	46.8	0.43	55	5.7	40.9	64.2	18.1	45.3	10.6	37.0	13.0	34.4-28.9	14.7	19.8
139	Soso (11,701 Bailey, Rodessa, L. Cre.)	41.1	0.86	41	9.9	36.5	68.7	18.1	45.2	10.0	34.8	15.4	34.0-26.6	19.4	13.3
140	Tinsley (Selma, U. Cre.)	30.4	1.08	79	8.5	20.9	65.1	11.1	44.7	11.4	36.0	18.6	31.7-22.0	37.8	13.8
	Montana														
141	Cabin Creek (Mission Canyon, Miss.)	33.4	0.60	47	15.7	25.1	61.5	18.1	43.6	13.9	34.6	12.3	31.7-23.8	31.0	12.0
142	Cut Bank (Cut Bank, L. Cre.)	38.0	0.86	38	9.9	34.3	60.5	10.6	42.3	15.8	34.6	19.3	30.8-24.2	17.0	14.8
143	Pine (Dev.)	33.8	0.36	55	18.9	34.7	64.2	19.8	46.0	11.9	36.2	10.6	31.5-23.5	31.2	9.7
144	Poplar East (Madison, Miss.)	36.6	0.32	38	4.4	33.8	60.2	12.3	43.8	17.5	36.0	17.5	31.9-26.3	18.7	19.3
145	Sumatra (Amsden, Penn.)	29.5	0.65	72	11.2	16.2	53.5	10.9	41.9	16.8	35.2	22.5	32.5-24.7	32.5	14.4
	New Mexico														
146	Bisti (Gallup, Cre.)	37.6	0.18	40	5.6	31.4	57.9	4.0	41.7	19.4	36.4	16.5	32.5-24.9	24.2	17.3
147	Caprock, East (Wolfcamp, Perm.)	43.2	0.17	35	3.3	46.0	56.7	12.2	42.3	17.3	35.8	12.4	32.7-27.3	11.7	21.3
148	Denton (Dev.)	46.0	0.17	35	4.0	44.3	61.0	11.3	42.8	16.3	36.0	13.3	33.0-28.2	11.5	21.6
149	Eunice-Monument (Grayburg, Perm.)	28.8	0.97	54	10.9	27.9	58.2	5.0	40.2	18.3	32.7	17.9	27.7-21.5	27.6	13.3
150	Gladiola (Wolfcamp, Perm.)	42.1	0.10	35	4.6	46.6	57.7	5.7	41.1	21.3	34.6	12.8	31.0-25.7	12.4	18.1
151	Hobbs (San Andres, Perm.)	37.4	1.41	41	9.6	35.5	60.8	4.5	41.3	17.0	34.0	19.6	28.6-20.7	17.9	11.1
152	Jalmat (Yates, Perm.)	36.2	1.22	47	6.0	32.8	58.2	10.5	42.8	13.4	36.0	19.0	31.5-23.8	21.6	12.6
153	Kemnitz (Wolfcamp, Perm.)	36.4	0.12	35	5.8	44.8	49.9	4.9	41.1	19.9	32.3	16.3	27.0-21.1	13.1	16.0
154	Langlie-Mattix (Queen, Perm.)	28.9	1.65	64	9.2	20.4	50.9	6.2	41.3	22.6	35.0	20.4	28.8-20.8	29.5	13.6
155	Lovington (Abo, Perm.)	39.4	0.36	36	4.6	41.0	55.7	5.0	41.5	19.0	34.0	13.6	29.3-24.0	18.0	17.9
156	Maljamar (Perm.)	38.6	0.70	37	8.8	37.5	57.7	4.7	42.8	19.7	35.6	17.3	30.8-24.2	19.0	15.7
157	Saunders (Wolfcamp, Perm.)	41.7	0.11	34	4.0	46.9	56.4	5.2	41.9	19.8	34.6	12.8	30.6-25.4	13.6	18.5
158	Vacuum (San Andres, Perm.)	35.0	0.95	43	9.2	33.5	54.0	4.7	42.6	21.3	35.0	17.1	30.0-22.5	22.3	14.4
159	Verde-Gallup (Mancos, Cre.)	39.6	0.12	30	3.4	31.6	59.2	10.7	42.6	16.0	37.4	19.1	34.2-25.9	20.7	20.3
	North Dakota														
160	Antelope (Miss.)	42.8	<0.10	32	2.7	41.9	60.0	10.8	42.3	15.8	35.2	17.0	32.7-23.5	12.8	20.0
161	Beaver Lodge-Tioga (Mission-Canyon, Ord.)	46.0	0.23	34	2.7	46.6	60.8	9.8	42.1	13.1	35.0	13.9	31.0-26.3	12.2	20.3
162	Blue Butte (Madison, Miss.)	41.1	0.32	34	2.6	41.0	57.4	10.0	42.8	17.0	34.6	14.0	31.1-26.4	16.8	19.4
163	Tioga (Madison, Miss.)	41.3	0.31	35	2.8	40.7	59.5	11.3	43.0	16.3	35.0	15.9	31.1-25.9	15.3	20.0
	Oklahoma														
164	Bradley (Springer, Penn. & Cunningham, Miss.)	35.0	0.22	50	6.7	34.3	57.4	15.6	43.0	9.6	36.6	19.5	34.8-27.1	30.4	18.6
165	Burbank (Layton, Penn.)	39.6	0.24	43	4.4	30.2	60.0	10.1	42.8	14.8	36.4	15.8	33.2-27.5	26.0	21.5
166	Cement (U. Melton, Penn.)	33.2	0.47	56	5.3	28.9	53.2	9.7	42.1	13.0	36.0	18.3	33.0-26.3	29.8	15.9
167	Cushing (Bartlesville, Penn.)	42.1	0.22	38	5.6	41.2	61.3	11.8	42.8	14.5	36.6	14.4	33.4-27.0	17.0	18.6
168	Eola-Robberson (Bromide, M. Ord.)	39.8	0.35	41	3.9	33.1	60.8	10.1	42.3	14.0	35.8	15.3	32.7-25.6	22.7	18.9
169	Eola-Robberson (Oil Creek, L. Ord.)	36.0	0.27	48	3.5	32.6	58.4	10.4	42.8	15.7	36.0	14.7	32.7-27.3	24.6	19.4
170	Glennpool (Glenn, Penn.)	37.4	0.31	42	6.5	32.3	56.9	12.0	42.3	16.4	36.0	15.7	32.5-26.1	23.0	18.1
	Golden Trend														
171	Antioch, Southwest (Gibson, Miss.)	43.1	0.11	30	2.7	34.6	62.9	17.1	42.8	8.1	36.0	15.3	34.4-27.5	22.3	23.3

Table A-2 (Continued). PROPERTIES OF UNITED STATES CRUDE OILS

Item No.	State Field (Formation, age)[1]	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
172	Elmore, Northeast (Gibson, Miss.)	42.1	0.14	38	3.0	37.0	62.1	17.4	43.0	8.8	36.4	15.9	34.4-28.4	20.2	22.6
173	New Hope, Southeast (Gibson, Miss.)	41.1	0.19	41	4.3	32.7	62.1	11.1	43.8	15.1	37.6	20.0	34.0-26.8	19.0	21.1
174	Panther Creek (Penn.)	46.5	0.14	37	3.8	51.5	61.5	11.6	43.8	12.1	37.2	11.3	34.0-27.7	13.3	20.8
175	Healdton (Healdton, Penn.)	28.9	0.92	110	10.7	17.2	54.2	3.9	42.8	20.0	37.0	21.3	32.5-25.2	36.7	15.0
176	Hewitt (Lone Grove, Pre-Cam.)	37.0	0.65	49	8.3	28.6	61.0	9.7	43.6	13.5	37.0	16.4	33.2-24.9	29.0	16.8
177	Joiner City (Bois D'Arc, Sil.-Dev.)	40.4	0.47	40	4.0	34.9	63.7	9.9	43.6	12.2	37.0	15.7	33.4-25.2	24.3	18.9
178	Knox (Dornick Hills, Penn.)	43.0	<0.10	37	3.6	37.3	60.0	11.9	43.4	14.0	37.6	18.8	35.4-28.4	16.3	22.8
179	Naval Reserve (Burbank, Penn.)	39.8	0.25	42	4.0	31.2	60.5	10.3	42.8	14.8	36.8	16.4	33.6-28.0	25.6	22.3
180	Oklahoma City (Wilcox, Ord.)	37.6	0.16	45	4.2	27.5	58.2	10.6	42.8	15.3	36.8	18.8	34.4-27.5	26.0	21.0
	Sho-Vel-Tum District														
181	Camp (Springer, Penn.)	28.0	1.41	115	11.4	22.2	58.2	4.1	42.3	16.0	36.2	15.8	34.2-26.8	40.9	12.6
182	Fox-Graham (Springer, Penn.)	36.0	0.57	49	6.6	27.0	57.4	11.5	43.6	15.5	37.2	15.8	34.0-26.3	29.0	17.9
183	Milroy (Deese, Penn.)	30.0	1.73	100	11.8	22.6	59.7	8.8	42.3	13.0	35.4	14.8	31.7-23.8	39.8	13.2
184	Sholem Alechem (Springer, Penn.)	20.8	1.44	150	7.9	21.5	56.7	3.3	42.6	14.8	35.4	15.5	30.4-21.8	43.2	10.6
185	Tatums (Deese, Penn.)	21.0	1.68	550	8.2	14.5	55.9	3.1	41.7	13.6	34.2	10.1	29.3-22.5	55.9	8.3
186	Velma (L. Dornick Hills, Springer, Penn.)	29.1	1.36	87	10.1	21.2	59.5	4.3	42.8	15.9	34.8	16.6	30.0-22.8	40.4	13.9
	Pennsylvania														
187	Bradford (U. Dev.)	41.1	0.11	44	1.6	30.7	56.2	18.1	44.1	8.7	38.4	15.9	36.8-31.1	25.0	25.7
	Texas														
188	Anahuac (Marg. No. 1, Olig.)	33.2	0.23	48	4.0	17.7	51.8	7.0	42.1	32.4	35.2	21.1	31.9-25.9	21.6	19.4
189	Andector (Ellen, Cam.-Ord.)	43.2	0.22	38	4.9	34.9	64.2	18.7	44.9	9.8	38.6	15.1	36.6-28.0	20.0	20.7
190	Andrews (Penn.)	39.0	0.11	41	5.0	33.8	59.2	10.1	42.3	14.1	36.2	16.4	34.6-26.8	21.2	19.8
191	Andrews (Wolfcamp, Perm.)	36.8	0.78	40	7.6	37.0	56.4	4.5	41.9	19.3	34.6	14.1	30.2-24.0	23.6	16.0
192	Andrews, North (Dev.)	44.3	0.30	37	3.7	39.3	62.9	10.7	44.3	14.1	37.8	15.1	34.4-27.7	17.6	22.1
193	Andrews, North (Ellen, Cam.-Ord.)	45.2	0.11	37	7.8	37.0	68.1	19.6	47.6	13.0	37.0	12.8	34.4-26.4	16.0	18.6
194	Andrews, South (Dev.)	44.7	<0.10	36	9.1	42.2	60.8	17.1	43.0	8.7	37.2	16.1	36.0-29.1	14.8	24.9
195	Andrews, South (Wolfcamp, Perm.)	36.8	0.10	40	5.6	32.0	55.9	10.5	42.3	15.9	37.2	16.3	34.6-28.0	25.0	19.5
196	Bakke (Dev.)	44.7	0.16	37	1.1	42.4	61.3	10.7	43.8	15.0	38.0	15.0	35.4-29.9	15.0	24.3
197	Bakke (Ellen, Cam.-Ord.)	45.6	0.21	<32	6.3	36.7	65.7	19.5	45.8	13.1	38.0	11.1	35.0-27.7	18.2	25.7
198	Bakke (Penn.)	39.4	<0.10	40	2.2	33.9	58.9	10.7	43.4	14.2	37.6	17.7	35.2-28.6	22.7	21.8
199	Bakke (Wolfcamp, Perm.)	37.4	0.41	40	4.7	35.8	55.2	4.3	43.0	20.3	36.0	15.0	32.1-26.3	22.4	18.2
200	Bethany (4300' Glen Rose, L. Cre.)	41.5	0.23	41	6.8	30.9	61.5	21.6	47.4	10.0	37.8	16.5	36.2-29.1	19.4	19.0
201	Block 31 (Dev.)	44.5	0.18	35	3.9	43.3	61.8	10.4	43.0	13.1	37.2	15.5	34.4-27.1	15.2	21.6
202	Borregos (F-5, Frio, Olig.)	42.1	<0.10	35	3.3	42.3	55.9	6.6	42.6	32.6	35.6	12.3	31.7-22.0	4.3	12.5
203	Borregos (L-5, Frio, Olig.)	40.6	<0.10	36	3.9	38.2	53.5	17.3	42.3	21.4	34.2	13.0	31.5-19.0	5.7	11.3
204	Borregos (N-21, Frio, Olig.)	42.3	<0.10	35	4.0	31.6	54.0	25.6	42.1	32.2	36.0	7.5	33.2-23.0	2.0	13.2
205	Borregos (R-13, Vicksburg, Olig.)	38.2	<0.10	37	3.5	23.3	54.4	5.5	43.6	48.6	35.6	17.1	32.8-23.3	5.0	13.0
206	Borregos, South (R-5, Frio, Olig.)	39.0	<0.10	35	3.9	29.9	52.7	17.8	42.3	30.3	35.6	15.9	32.5-23.1	5.1	13.6
207	Cogdell area (Canyon Reef, Penn.)	41.7	0.38	37	7.6	38.2	62.6	9.9	42.1	14.4	35.8	14.4	32.7-26.8	19.9	17.5
208	Conroe (Cockfield, Eoc.)	37.0	<0.10	36	4.9	32.8	48.8			43.4	34.4	15.9	31.3-26.3	7.2	17.5
209	Cowden, North (Grayburg, Perm.)	30.4	1.89	51	10.9	27.7	54.4	5.0	43.0	19.5	35.0	18.1	30.4-22.5	29.7	12.3
210	Cowden Deep (San Andres, Perm.)	36.6	0.96	42	6.7	35.0	58.7	10.4	41.7	15.0	34.8	15.0	31.7-24.7	24.6	17.1
211	Cowden, South (Grayburg, Perm.)	34.6	1.77	44	3.5	32.6	57.9	3.6	42.1	18.5	35.0	15.5	30.2-23.0	26.8	13.5
212	Darst Creek (Buda, L. Cre.)	36.6	0.76	49	7.8	23.5	58.9	22.5	44.1	12.2	36.0	18.8	34.6-28.0	22.5	17.5
213	Darst Creek (Edwards, L. Cre.)	36.8	0.78	46	6.8	25.7	57.9	19.4	43.4	13.1	36.4	17.9	34.6-28.6	23.2	17.8
214	Diamond "M" (Canyon Reef, Perm.)	45.4	0.20	35	4.9	43.0	61.5	5.0	42.3	17.5	36.6	13.5	32.8-27.7	16.1	20.2
215	Dollarhide (Clear Fork, Perm.)	37.4	0.42	43	5.8	33.4	60.5	11.1	42.6	13.8	35.8	17.5	32.7-24.9	24.0	17.9
216	Dollarhide (Dev.)	38.2	0.57	41	6.4	35.8	61.3	9.8	41.9	13.2	34.8	15.0	31.3-25.9	24.7	17.3
217	Dollarhide (Ellen., Cam.-Ord.)	41.5	0.23	40	6.0	31.6	65.0	20.9	46.7	14.5	37.8	11.5	34.8-27.7	21.4	19.7
218	Dollarhide (Sil.)	41.3	0.36	39	8.3	32.4	65.9	20.0	45.6	13.1	37.2	12.0	34.4-26.1	22.2	17.8
219	Dollarhide, East (Ellen., Cambro-Ord.)	42.3	0.10	40	4.3	35.7	62.9	17.2	44.5	9.8	36.4	13.6	34.6-27.3	20.9	21.0
220	Dune (Grayburg, Perm.)	29.7	3.11	57	7.4	24.4	55.9	4.8	42.1	20.7	35.2	14.6	30.4-24.3	35.0	13.2
221	East Texas (Woodbine, U. Cre.)	37.4	0.25	42	6.1	33.9	58.2	5.0	42.8	17.7	37.2	20.3	34.2-25.9	22.2	16.4
222	Emma (Dev.)	45.6	<0.10	36	2.9	39.9	62.9	11.9	44.5	14.8	38.2	13.5	35.2-28.4	16.7	23.3
223	Emma (Ellen., Cam.-Ord.)	49.2	<0.10	35	5.6	42.0	65.6	20.8	46.0	12.6	39.4	13.4	36.4-27.5	8.8	21.8
224	Emma (Grayburg-San Andres, Perm.)	49.0	<0.10	35	3.4	39.6	67.5	21.3	47.4	13.4	38.6	9.3	35.8-31.5	13.2	23.8
225	Emperor, Deep (Seven Rivers, Queen, Perm.)	35.6	1.11	45	7.1	34.0	57.7	10.8	42.3	14.0	34.6	16.1	30.0-23.5	24.4	15.7
226	Fairway (James, L. Cre.)	45.6	0.24	33	2.0	36.1	62.7	18.8	45.4	10.4	36.3	16.4	35.2-28.1	13.4	24.0
227	Fort Chadbourne (Odem, Penn.)	44.1	0.24	37	3.4	39.9	61.0	11.2	43.6	15.3	37.8	15.1	35.2-29.3	16.7	23.0
228	Foster (Grayburg, Perm.)	34.2	1.53	44	7.4	31.6	57.4	4.7	42.1	19.9	35.2	16.8	30.6-24.3	26.5	15.3
229	Fuhrman-Mascho (Grayburg, Perm.)	31.3	2.06	47	8.4	33.1	55.2	5.5	41.7	17.7	33.4	15.8	28.6-20.8	27.7	10.0
230	Fullerton (Clear Fork, Perm.)	39.6	0.47	40	5.8	35.1	58.7	10.9	43.2	14.2	36.0	16.3	33.0-26.4	21.0	19.4
231	Fullerton (Dev.)	41.5	0.32	38	4.4	37.4	61.3	11.4	43.6	15.6	37.4	15.8	34.6-28.8	19.6	22.0
232	Fullerton, South (Wolfcamp, Perm.)	43.4	0.17	36	3.0	39.5	61.3	10.6	43.8	13.7	37.2	14.8	33.6-27.9	18.3	22.1

Table A-2 (Continued). PROPERTIES OF UNITED STATES CRUDE OILS

Item No.	State Field (Formation, age)[1]	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
233	Gillock (Hudgings, Frio, Olig.)	45.2	<0.10	34	3.5	38.2	60.2	16.5	43.2	21.6	37.0	14.2	34.6-26.1	6.6	19.8
234	Gillock, South (Frio, Olig.)	38.0	0.11	38	6.0	28.3	56.9	7.3	43.0	32.8	36.2	19.1	32.8-27.1	12.2	17.9
235	Goldsmith (5600', U. Clear Fork, Perm.)	38.0	0.52	46	5.7	30.4	58.7	10.7	43.6	15.0	36.6	16.7	33.4-23.5	24.1	18.2
236	Goldsmith (Clear Fork-Tubb, Perm.)	38.0	0.57	44	5.1	30.2	58.9	11.7	43.8	15.5	36.8	16.3	34.6-26.3	24.6	19.4
237	Goldsmith (Dev.)	40.9	0.16	40	5.2	35.4	61.8	10.5	43.4	13.2	36.4	16.0	33.6-27.3	21.9	19.7
238	Goldsmith (San Andres, Perm.)	38.4	1.16	40	6.7	35.4	56.7	4.5	42.8	18.1	35.8	15.6	31.0-20.8	21.7	15.3
239	Goldsmith, East (Holt, Perm.)	36.4	0.15	50	4.8	29.5	54.9	5.3	42.6	19.7	36.8	17.9	33.0-26.8	25.6	19.2
240	Goldsmith, North (Ellen., Cam.-Ord.)	37.0	0.56	44	5.6	29.6	58.9	10.4	43.5	15.6	36.2	17.8	33.0-25.0	24.7	17.5
241	Goldsmith, West (U. Clear Fork, Perm.)	37.4	0.53	44	5.2	31.7	60.2	10.2	43.4	14.6	36.4	16.1	32.8-25.9	20.4	18.2
242	Goldsmith, West (Ellen., Cam.-Ord.)	42.6	0.32	39	3.7	33.1	64.5	18.7	45.6	13.2	38.4	12.6	35.4-27.7	21.0	21.3
243	Goldsmith, West (Fusselman, Sil.)	37.4	0.96	43	6.1	31.9	60.0	9.8	42.6	15.8	35.0	15.3	31.3-25.2	25.4	16.8
244	Goldsmith, West (San Andres, Perm.)	34.4	1.38	43	9.1	33.2	56.7	11.0	41.7	16.2	31.3	14.1	30.0-25.0	24.8	13.6
245	Goose Creek (Frio, Olig.)	35.0	0.13	42	4.3	22.1	54.2	6.1	42.6	32.6	35.0	21.3	30.6-25.0	17.7	19.7
246	Hastings (Marginulina, Olig.)	31.5	0.15	48	4.7	20.1	52.0	......	......	36.9	33.4	22.7	29.5-21.6	20.3	18.2
247	Hastings, East (Frio, Olig.)	31.0	0.15	55	4.3	15.8	49.2	......	......	35.6	31.0	23.1	29.3-23.5	23.0	18.7
248	Hastings, West (Frio, Olig.)	30.2	0.17	56	5.8	16.4	50.6	......	......	35.6	33.6	23.0	28.6-22.6	22.4	17.0
249	Hawkins (Eagle Ford, U. Cre.)	26.8	2.19	135	6.0	20.7	63.1	7.3	44.5	12.7	35.4	15.4	30.6-22.0	43.1	9.3
250	Hendlee (Dev.)	47.4	<0.10	37	0.4	45.7	62.1	17.6	43.8	9.8	37.6	13.2	37.0-31.0	12.2	25.4
251	Hendlee (Ellen., Cam.-Ord.)	51.1	<0.10	35	1.5	43.0	67.0	22.3	48.5	14.7	40.2	8.8	38.0-32.8	9.8	26.3
252	High Island (Mio.)	27.3	0.26	79	6.2	10.1	47.2	......	......	38.6	32.1	30.1	28.0-20.5	21.0	18.7
253	Howard-Glasscock (Yates, Perm.)	30.6	1.18	61	7.6	21.8	53.2	......	......	24.5	35.0	19.5	31.5-25.4	33.3	17.3
254	Hull (Caprock, Mio.)	31.1	0.35	41	3.7	33.4	51.8	......	......	20.5	29.3	10.1	22.1-16.8	17.5	16.5
255	Jameson (Strawn, Penn.)	40.9	<0.10	34	1.6	30.3	56.9	13.5	43.0	15.0	38.6	17.1	34.4-29.9	17.1	23.7
256	Jameson (Strawn Reef, Penn.)	44.3	<0.10	36	1.3	41.7	60.0	18.0	42.6	8.6	36.6	14.3	35.4-30.0	15.6	25.0
257	Jo-Mill (Spraberry, Perm.)	37.4	0.11	43	3.7	32.6	57.7	4.5	41.7	17.6	35.8	15.2	31.9-27.5	27.8	19.8
258	Jordan (Ellen., Cam.-Ord.)	43.1	0.28	38	5.2	34.5	65.3	10.9	54.7	14.3	38.0	10.4	35.4-29.1	20.0	20.8
259	Jordan (San Andres, Perm.)	33.2	1.48	46	9.4	29.7	55.9	5.1	43.0	20.1	36.0	18.6	30.4-23.5	26.4	14.5
260	Kelly-Snyder (Canyon Reef, Penn.)	39.8	0.22	37	4.8	42.2	57.4	4.9	41.9	19.2	35.8	14.9	32.1-26.3	18.4	19.2
261	Kelsey (Frio, Olig.)	40.6	0.13	35	8.9	38.5	57.4	6.3	43.6	33.4	35.4	14.1	33.1-17.6	6.8	9.9
262	Kelsey, South (18-A, Frio, Olig.)	43.4	<0.10	34	2.9	45.3	55.4	18.8	42.6	19.8	34.8	5.5	31.3-22.8	9.0	16.7
263	Kermit (Ellen., Cam.-Ord.)	41.9	0.19	39	2.3	30.0	61.8	19.2	44.9	13.1	37.2	16.8	35.2-29.9	20.3	24.3
264	Kermit (Yates and Seven Rivers, Perm.)	36.6	0.94	42	7.2	34.8	59.5	5.0	41.9	18.5	35.0	17.5	29.9-23.1	22.8	16.2
265	Kermit, South (Dev.)	32.3	0.79	81	4.8	17.0	58.7	8.6	43.8	13.1	36.8	22.6	32.7-26.8	37.5	19.7
266	Keystone-Colby (Queen, Perm.)	34.2	0.95	48	5.7	26.1	54.2	12.6	42.1	16.7	35.4	16.9	32.1-25.9	26.7	17.6
267	Keystone-Devonian (Dev.)	32.7	0.69	68	5.2	18.6	57.7	8.2	43.0	15.6	36.4	22.6	33.2-26.8	34.5	20.3
268	Keystone-Ellenburger (Ellen., Cam.-Ord.)	42.1	0.13	40	2.3	30.0	62.9	20.1	45.4	15.0	37.8	14.4	35.6-29.1	19.1	22.8
269	Keystone-Holt (San Angelo, Perm.)	37.8	0.63	43	5.1	31.7	57.7	11.8	43.6	17.1	36.6	15.4	33.2-26.6	23.3	18.4
270	Keystone-Silurian (Sil.)	35.4	0.49	51	5.2	21.9	57.4	19.5	43.4	12.8	36.2	17.3	34.0-27.3	28.5	19.5
271	KMA (Strawn, Penn.)	40.0	0.31	39	6.3	36.9	57.9	11.4	42.1	15.7	35.4	15.5	32.7-25.7	18.7	18.2
272	Lake Pasture (FT-560, Frio-Sinton, Olig.)	37.2	0.13	35	4.7	32.0	52.5	9.0	42.1	37.6	34.2	15.1	28.9-17.5	3.4	11.0
273	Lake Pasture (H-440, Greta, Olig.)	23.7	0.20	60	5.3	2.8	43.2	......	......	50.3	30.0	34.3	25.0-13.9	12.1	9.9
274	Levelland (San Andres, Perm.)	31.1	2.12	48	8.6	31.0	54.2	4.2	42.3	17.8	34.0	17.1	28.9-21.8	28.3	10.4
275	Liberty, South (EY, Olig.)	36.4	0.14	40	2.5	30.6	53.7	5.6	42.6	26.8	34.6	19.9	31.1-25.2	10.5	19.8
276	Luling-Branyon (Edwards, L. Cre.)	28.6	0.86	90	6.6	12.7	51.6	4.8	41.3	24.4	34.8	22.7	30.8-23.7	35.4	17.9
277	Magutex (Dev.)	40.2	0.30	38	4.3	38.5	58.4	11.0	42.3	15.6	36.6	15.8	34.0-28.0	18.9	20.8
278	Magutex (Ellen., Cam.-Ord.)	46.9	0.12	39	4.0	36.4	65.3	22.1	47.2	13.4	39.4	13.5	37.0-28.4	13.1	23.0
279	McElroy (Grayburg, Perm.)	31.5	2.37	53	10.5	24.7	57.4	4.4	41.9	20.2	35.0	19.5	29.7-22.8	29.6	13.3
280	Means (Grayburg, Perm.)	30.0	2.40	54	8.5	29.7	56.7	4.3	42.3	13.6	33.6	15.6	28.0-21.5	30.9	9.9
281	Means (Queen, Perm.)	35.6	1.11	46	11.8	31.3	59.7	10.2	43.2	12.6	35.6	15.1	31.9-25.4	28.5	13.9
282	Means, East (Strawn, Penn.)	43.0	0.10	35	3.0	45.2	58.4	5.3	42.1	17.5	36.4	14.6	32.3-26.8	15.4	21.5
283	Midland Farms (Ellen., Cam.-Ord.)	50.6	<0.10	34	2.2	42.8	66.1	22.5	48.3	14.0	39.6	9.6	37.0-32.7	9.4	27.1
284	Midland Farms (Grayburg, Perm.)	31.7	2.04	46	11.3	20.5	57.9	4.7	42.1	10.2	34.0	16.6	28.6-22.1	28.8	11.6
285	Midland Farms (Wolfcamp, Perm.)	39.6	0.13	40	3.1	36.6	56.9	10.3	41.3	13.5	35.6	15.5	33.2-27.3	22.1	21.3
286	Midland Farms, North (Grayburg, Perm.)	30.0	2.37	53	6.9	28.3	57.4	4.0	42.3	17.7	33.6	16.2	28.2-21.1	31.7	10.1
287	Midland Farms, Northeast (Ellen., Cam.-Ord.)	49.2	<0.10	38	3.0	41.3	64.8	23.5	47.8	14.4	39.8	11.6	37.8-30.2	8.7	23.5
288	Old Ocean (Armstrong, Frio, Olig.)	36.8	0.14	43	4.6	24.8	54.7	13.8	41.7	23.0	35.0	18.2	32.8-26.3	19.6	19.5
289	Old Ocean (Chenault, Frio, Olig.)	25.4	0.21	71	4.0	3.6	44.3	......	......	43.9	30.0	27.5	26.3-20.8	24.7	17.3
290	Panhandle (Moore County, Perm.)	40.4	0.55	47	5.6	31.1	61.5	8.7	43.6	13.6	38.4	16.1	36.0-31.1	37.2	20.0
291	Pegasus (Ellen., Cam.-Ord.)	53.0	<0.10	33	1.6	46.3	67.5	21.2	48.5	12.9	40.9	8.4	38.0-33.4	8.3	27.9
292	Pegasus (Penn.)	45.4	<0.10	36	1.3	42.9	61.0	9.8	43.2	12.7	36.4	13.8	33.2-27.5	17.1	23.5
293	Pegasus (Spraberry, Perm.)	35.6	0.17	48	8.5	31.9	59.2	9.4	41.9	12.4	36.4	16.3	32.3-24.7	28.4	16.5
294	Penwell (Ellen., Cam.-Ord.)	41.7	0.24	40	8.2	32.3	65.9	19.5	45.8	12.7	38.0	12.1	35.0-27.0	22.0	17.8
295	Penwell (San Andres, Perm.)	33.2	1.69	45	8.3	31.0	55.0	4.9	43.0	19.8	35.6	16.4	30.6-22.3	27.7	15.1
296	Pierce Junction (Frio, Olig.)	37.2	0.12	39	5.6	40.0	53.7	6.7	40.2	21.5	33.0	17.5	29.9-20.5	14.3	17.5
297	Plymouth (6100', Frio, Olig.)	42.3	0.12	34	6.1	44.2	57.4	8.0	44.3	30.8	34.6	10.9	28.2-15.1	5.0	9.2
298	Plymouth (Frio, Olig.)	40.6	0.13	37	5.4	47.0	56.9	7.6	42.1	26.3	37.8	12.1	27.0-14.8	6.0	8.9

Table A-2 (Continued). PROPERTIES OF UNITED STATES CRUDE OILS

tem No.	*State* Field (Formation, age)[1]	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
299	Plymouth (Greta, Frio, Olig.)	23.5	0.19	55	4.7	6.1	54.7	......	......	47.4	28.9	31.0	23.8-12.0	15.1	9.3
300	Plymouth (Main Greta, Frio, Olig.)	28.8	0.15	44	5.8	19.8	51.1	......	......	42.3	30.6	26.4	24.7-11.7	9.8	9.2
301	Portilla (7100′, Frio, Olig.)	40.4	<0.10	34	4.3	39.6	55.9	9.1	43.2	34.4	33.8	11.6	28.2-15.3	4.3	9.7
302	Portilla (7300′, Frio, Olig.)	39.8	<0.10	36	4.3	38.6	55.2	7.4	41.7	32.8	34.8	12.4	29.3-19.0	6.6	10.7
303	Portilla (7400′, Frio, Olig.)	39.6	0.14	35	4.6	37.8	54.9	7.1	42.3	35.9	34.4	13.2	30.0-19.5	5.3	10.7
304	Portilla (8100′, Frio, Olig.)	39.0	0.12	35	4.8	30.5	53.7	7.9	42.6	42.8	34.6	14.6	31.5-20.3	4.0	10.9
305	Prentice (6700′, Clear Fork, Perm.)	25.9	2.60	54	9.4	29.4	52.3	4.7	41.1	19.1	31.7	16.4	24.7-17.8	30.3	5.8
306	Prentice (Glorieta, Perm.)	28.6	2.68	47	5.8	31.9	54.2	4.5	41.1	19.4	31.0	15.8	24.9-18.1	27.2	5.9
307	Quitman (Eagle Ford, U. Cre.)	26.3	2.06	145	5.8	15.4	59.7	7.4	42.3	14.9	34.6	15.9	31.3-25.7	45.8	12.5
308	Quitman (Sub-Clarksville, U. Cre.)	16.2	3.64	3,700	12.0	8.6	58.9	2.2	42.8	13.7	34.4	19.6	27.5-17.0	55.0	4.2
309	Quitman (Trinity, L. Cre.)	43.8	0.92	39	8.5	43.8	66.4	16.9	44.1	8.6	35.4	12.0	32.8-26.6	18.4	15.4
310	Robertson (L. Clear Fork, Perm.)	34.0	1.31	44	9.2	32.4	56.7	4.7	42.1	19.2	35.4	17.0	30.6-24.0	25.5	13.5
311	Robertson (San Angelo-Clear Fork, Perm.)	29.9	1.95	49	6.1	29.1	53.7	4.0	41.7	18.6	33.8	16.3	28.0-22.1	31.4	12.9
312	Robertson, North (7100′, Clear Fork, Perm.)	34.8	0.79	44	8.4	31.5	56.2	10.3	41.9	14.8	35.2	17.8	31.9-25.0	25.0	15.9
313	Russell (6100′ Glorieta, Perm.)	32.7	1.20	40	11.7	35.7	53.7	5.1	41.9	20.2	32.3	15.0	26.6-21.5	22.8	10.7
314	Ryssell (7000′ Clear Fork, Perm.)	34.6	1.23	39	10.6	38.2	55.4	4.6	41.5	19.5	32.3	14.3	26.6-21.6	21.7	11.4
315	Russell, North (Dev.)	40.2	0.31	37	7.8	35.9	61.3	10.3	42.1	14.9	35.0	13.8	31.7-25.2	22.1	16.4
316	Salt Creek (Canyon, Penn.)	36.8	0.63	41	10.3	33.4	59.5	10.5	41.7	15.0	35.2	15.4	32.5-26.3	24.3	15.6
317	Sand Hills (Ellen., Cam.-Ord.)	37.0	0.73	45	5.4	27.7	60.2	19.2	43.4	12.7	35.0	12.3	32.5-25.9	26.2	17.0
318	Sand Hills (McKnight, San Andres, Perm.)	31.7	3.33	45	9.9	34.3	57.2	4.4	42.1	18.4	34.2	17.5	28.2-22.5	23.9	4.7
319	Sand Hills (Tubb, Perm.)	36.8	0.92	42	7.6	33.6	59.5	10.6	43.4	14.9	36.4	15.5	32.7-26.1	25.0	16.8
320	Scarborough (Yates, Perm.)	34.0	1.00	47	8.2	30.2	57.2	6.0	42.6	20.2	35.4	19.5	30.2-22.8	23.7	15.1
321	Seeligson (Zone 14-B, Frio, Olig.)	41.5	<0.10	34	3.9	40.2	54.7	8.0	42.1	33.3	35.8	12.1	31.7-22.0	5.2	13.5
322	Seeligson (Zone 19-B, Frio, Olig.)	41.3	<0.10	35	6.9	39.0	54.4	18.8	41.5	22.7	34.6	12.7	31.9-20.0	5.4	11.4
323	Seeligson (Zone 19-C, Frio, Olig.)	41.9	<0.10	36	4.4	38.8	55.2	9.5	44.3	34.5	36.2	12.2	31.5-20.5	4.0	12.6
324	Seeligson (Zone 20, Frio, Olig.)	40.2	<0.10	34	3.4	40.2	53.2	8.9	43.3	31.7	34.8	13.2	30.6-19.4	5.8	12.3
325	Seeligson (Zone 21-D, Frio, Olig.)	41.5	0.12	36	4.4	28.8	56.2	21.0	43.2	28.1	36.2	14.9	34.0-21.5	5.2	13.6
326	Seminole (San Andres, Perm.)	33.6	1.86	43	9.7	32.7	57.7	5.0	42.6	19.4	34.4	16.0	29.1-22.5	26.0	12.5
327	Seminole, West (San Andres, Perm.)	31.7	2.27	45	12.2	32.9	55.9	5.0	42.8	19.0	34.4	15.1	28.9-22.0	27.8	10.6
328	Shafter Lake (Dev.)	38.6	0.77	40	7.6	33.7	61.0	4.5	42.6	18.8	36.4	16.4	32.7-26.3	24.4	17.0
329	Shafter Lake (San Andres, Perm.)	37.4	0.25	46	6.0	26.5	56.2	20.5	43.4	10.9	37.0	16.6	35.6-28.2	25.2	19.7
330	Sharon Ridge (1700′ San Andres, Perm.)	27.1	2.04	58	6.6	26.9	54.7	4.3	41.7	18.1	32.5	16.5	26.6-21.0	33.0	7.5
331	Sharon Ridge (2400′ San Angelo, Perm.)	28.2	1.71	49	13.4	23.3	51.1	4.2	41.9	17.8	33.0	16.5	27.3-21.0	32.1	9.2
332	Sharon Ridge (Clear Fork, Perm.)	29.1	1.67	49	13.5	29.1	55.4	4.4	42.3	19.2	33.8	16.4	27.3-21.5	30.8	9.6
333	Shipley (Queen, Perm.)	36.0	1.34	41	8.9	34.7	59.5	9.7	41.7	14.4	34.4	16.2	30.6-24.0	23.9	14.2
334	Slaughter (San Andres, Perm.)	31.1	2.04	48	12.1	31.1	56.4	4.4	45.2	18.6	34.4	16.1	28.4-21.6	29.3	10.7
335	Spraberry Trend area (Spraberry, Perm.)	35.0	0.18	48	7.1	31.3	55.9	4.5	41.3	17.5	36.2	15.0	32.3-23.7	28.4	17.0
336	Taft (Frio, Olig.)	21.6	0.21	85	3.9	......	......	......	......	43.9	28.4	36.0	24.2-14.5	20.0	11.1
337	Talco (Trinity, L. Cre.)	20.5	3.00	520	17.6	10.7	58.9	7.0	42.3	13.7	34.2	17.9	33.8-24.7	50.7	9.7
338	Thompson (3600′, Mio.)	23.8	0.25	140	4.2	......	......	......	......	32.4	29.9	33.4	27.3-22.1	33.5	18.2
339	Thompson, North (Vicksburg, Olig.)	36.4	0.11	46	3.3	23.4	54.7	13.2	42.3	20.9	35.6	19.6	33.2-25.2	22.1	21.0
340	Thompson, South (Mio.)	25.7	0.20	64	4.4	7.2	45.2	......	......	42.4	28.4	27.7	24.7-20.5	22.6	18.1
341	Tijerina-Canales-Blucher (Frio, Olig.)	40.5	<0.10	35	7.7	37.7	54.9	17.5	43.0	23.8	35.6	14.5	33.4-19.7	6.4	12.2
342	Tom O'Connor (Frio, Olig.)	34.8	0.17	30	4.4	30.6	55.2	......	......	38.5	33.2	19.6	27.5-14.5	9.5	9.9
343	TXL (Dev.)	38.6	0.50	41	6.0	32.8	59.7	9.7	42.1	13.7	36.0	17.7	32.8-25.9	23.5	18.2
344	TXL (Ellen., Cam.-Ord.)	42.3	0.21	39	3.9	33.7	64.5	19.7	45.8	12.5	39.4	12.1	39.6-27.7	21.5	21.1
345	TXL (San Andres, Perm.)	30.8	1.93	49	9.8	28.9	52.0	5.0	42.6	20.3	34.4	17.4	29.3-22.0	26.8	11.9
346	TXL (Tubb, Perm.)	36.4	0.54	47	5.2	30.3	59.2	9.8	42.3	14.1	36.0	15.8	32.8-26.1	28.5	17.9
347	University-Block 9 (Dev.)	44.7	<0.10	36	2.7	39.1	62.3	17.1	43.2	9.1	35.6	14.0	34.0-29.3	17.4	22.8
348	University-Block 9 (Penn.)	36.4	0.12	45	5.3	29.5	56.7	11.0	42.3	14.7	30.4	17.1	33.6-28.9	26.7	19.5
349	University-Block 9 (Wolfcamp, Perm.)	37.0	0.57	39	6.2	36.4	56.4	5.2	42.1	19.5	35.0	15.9	30.2-25.7	21.0	16.0
350	Van (Woodbine-Dexter, U. Cre.)	35.4	0.82	51	8.3	26.5	64.8	15.1	43.9	9.5	32.5	17.5	32.3-24.5	30.1	16.0
351	Waddell (Grayburg, Perm.)	33.6	1.69	46	9.8	30.9	58.4	4.7	41.9	19.7	35.2	16.9	30.4-24.3	26.8	12.9
352	Walnut Bend (Hudspeth, Strawn, Penn.)	40.0	0.23	38	3.3	38.3	64.5	16.5	43.4	7.3	37.0	14.0	35.6-23.1	20.8	26.6
353	Walnut Bend (U. Strawn, Penn.)	44.1	0.17	38	3.5	37.5	64.2	16.5	44.1	9.3	37.0	14.5	35.8-29.1	20.6	23.3
354	Walnut Bend (Winger, L. Strawn, Penn.)	31.0	0.86	77	8.3	24.5	59.2	8.7	42.1	12.6	35.2	18.2	31.1-22.0	35.7	14.2
355	Ward-Estes, North (Yates, Perm.)	34.0	1.17	45	7.7	31.6	59.7	5.4	41.5	18.8	33.8	16.4	29.1-22.0	26.8	15.1
356	Ward, South, (Yates, Perm.)	35.8	1.12	42	8.0	33.8	58.2	5.3	42.6	19.5	35.2	17.2	30.4-23.0	23.8	15.7
357	Wasson (San Andres, Perm.)	32.8	1.76	43	5.2	33.3	57.2	4.5	42.6	19.6	34.2	14.3	29.3-22.8	27.8	11.9
358	Wasson 66 (Clear Fork, Perm.)	31.9	1.40	44	13.6	33.9	54.9	4.6	42.3	18.8	33.6	16.1	26.4-20.2	24.1	9.3
359	Wasson 72 (Clear Fork, Perm.)	33.2	1.01	42	11.9	35.9	54.4	4.9	42.6	19.6	33.4	16.6	27.3-21.0	21.7	11.0
360	Webster (Marginulina, Frio, Olig.)	29.3	0.21	64	4.6	14.5	49.7	......	......	31.4	32.8	25.2	28.9-22.5	27.6	18.4
361	Welch (San Andres, Perm.)	32.3	2.14	45	11.7	31.7	56.2	4.9	42.6	19.0	34.2	16.4	28.9-22.6	27.0	12.5
362	West Columbia ("Z," Frio. Olig.)	28.0	0.23	65	4.2	13.7	51.3	5.3	41.7	22.7	33.8	29.4	29.1-21.3	28.6	16.4
363	West Columbia New (Frio, Olig.)	28.6	0.19	63	6.2	14.1	50.1	5.7	41.3	27.7	32.7	25.3	28.4-21.5	26.9	16.2
364	West Ranch (41-A, Frio, Olig.)	31.5	0.17	41	3.5	25.7	51.1	......	......	41.4	31.0	21.0	26.1-14.4	9.7	11.9

Table A-2 (Continued). PROPERTIES OF UNITED STATES CRUDE OILS

Item No.	*State* Field (Formation, age)[1]	Gravity, °API	Sulfur, wt. per cent	Viscosity, SUS at 100°F	Carbon residue of residuum, wt. per cent	Gasoline and naphtha		Kerosine distillate		Gas oil distillate		Lubricating distillate		Residuum	
						Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API	Per cent	Gravity, °API
365	West Ranch (98-A, Frio, Olig.)	30.8	0.11	35	3.9	35.2	55.7	8.8	44.1	34.2	36.0	14.9	31.5-18.7	5.6	11.1
366	West Ranch (Glasscock, Frio, Olig.)	31.0	0.13	41	3.8	23.5	50.1	......	......	40.6	31.3	23.5	26.8-10.7	11.5	14.1
367	West Ranch (Greta, Olig.)	24.9	0.16	57	2.7	4.3	44.7	......	......	48.8	29.7	28.2	24.7-16.5	18.1	15.1
368	West Ranch (Ward, Frio, Olig.)	30.8	0.15	40	4.3	23.7	49.9	......	......	42.0	31.0	24.2	26.3-13.9	8.8	11.6
369	White Point, East (5900′ Greta, Olig.)	27.3	0.13	44	4.3	15.4	47.2	......	......	45.7	30.6	26.0	23.1-14.7	12.3	12.3
370	White Point, East (5000′ Brigham, Frio, Olig.)	38.4	0.13	35	3.5	40.5	54.7	7.0	42.0	30.8	32.3	14.3	26.6-16.5	6.6	12.9
371	Yates (San Andres, Perm.)	30.2	1.54	59	9.9	24.1	56.4	4.4	40.2	17.9	33.0	20.3	28.8-21.6	31.6	14.8
	Utah														
372	Aneth (Hermosa, Penn.)	40.4	0.20	38	3.5	35.0	59.5	10.2	42.1	16.9	36.8	15.7	34.2-31.0	21.2	23.1
373	McElmo Creek (Paradox, Penn.)	40.0	<0.10	37	3.0	34.0	57.9	11.5	42.6	9.5	37.8	19.9	35.2-28.9	24.0	22.8
374	Ratherford (Paradox, Penn.)	41.3	<0.10	37	2.9	34.5	59.7	10.0	42.8	16.8	36.8	15.1	34.4-28.2	21.3	22.3
375	White Mesa (Paradox, Penn.)	41.1	0.10	36	2.9	35.2	59.5	11.3	42.6	14.9	36.6	14.8	34.4-27.3	21.5	22.3
	Wyoming														
376	Beaver Creek (Steele, U. Cre.)	33.8	0.20	48	5.6	24.4	54.2	11.7	42.8	18.1	36.6	18.1	33.8-25.9	26.8	16.7
377	Big Muddy (Frontier, U. Cre.)	35.8	0.12	47	4.7	26.3	58.2	3.5	42.3	20.5	36.1	16.5	33.0-26.4	31.2	19.8
378	Big Sand Draw (Tensleep, Penn.)	34.2	1.35	43	12.4	26.6	60.0	12.8	43.6	17.8	34.8	19.7	30.4-21.5	21.8	11.6
379	Bonanza (Thermopolis, U. Cre.)	35.8	1.87	37	9.7	36.1	60.5	5.8	41.5	21.5	32.8	17.8	26.4-18.4	17.9	10.7
380	Byron (Tensleep, Penn.)	24.3	2.50	140	12.2	12.3	59.7	7.2	42.1	13.4	32.8	20.3	29.3-20.0	45.9	11.7
381	Cottonwood (Phosphoria, Perm.)	28.6	2.52	63	13.9	20.2	58.7	8.5	41.7	16.3	33.2	23.9	29.1-19.4	28.9	10.1
382	Coyote Creek (Minnelusa, Penn.)	40.9	<0.10	36	4.6	36.5	59.7	9.2	43.0	18.6	36.6	13.5	34.0-27.7	21.2	20.7
383	Donkey Creek (Dakota, L. Cre.)	39.4	0.12	37	4.0	34.4	59.5	10.8	41.5	14.9	36.0	13.8	33.8-27.7	24.3	19.5
384	Elk Basin (Frontier, U. Cre.)	43.2	<0.10	35	3.3	46.1	57.7	5.2	41.3	20.8	36.4	14.4	32.8-27.7	11.7	10.5
385	Four Bear (Madison, Miss.)	13.8	3.88	6,000	22.7	2.1	52.7	5.4	43.2	12.8	35.6	26.9	26.6-14.8	52.9	4.0
386	Frannie (Tensleep, Penn.)	27.5	2.43	66	11.6	19.0	58.9	4.3	42.4	18.6	34.4	21.7	27.5-19.4	35.2	10.9
387	Garland (Amsden, Penn.)	23.0	2.86	180	18.2	13.3	56.4	8.4	42.8	14.1	35.2	21.1	28.6-17.9	42.8	7.1
388	Glenrock (Dakota, L. Cre.)	34.4	0.16	38	6.5	24.9	55.7	6.7	43.2	17.0	37.0	18.1	34.6-23.0	34.7	18.7
389	Grass Creek (Frontier, U. Cre.)	44.8	<0.10	35	2.3	45.8	60.2	10.8	42.3	15.8	36.4	13.1	33.6-27.5	13.2	20.7
390	Grieve (L. Cre.)	38.2	<0.10	42	4.0	28.8	58.9	4.9	43.6	19.5	37.0	17.7	33.6-26.8	25.8	19.2
391	Hamilton Dome (Tensleep, Penn.)	22.6	2.98	230	15.2	11.2	58.9	8.7	44.1	12.2	34.2	22.4	29.5-19.7	45.1	9.0
392	Little Buffalo Basin (Phosphoria, Perm.)	20.7	3.31	340	15.3	12.1	60.2	6.3	41.7	12.0	32.7	19.4	27.5-18.1	49.3	8.2
393	Lost Soldier (Cam.)	35.2	1.23	41	11.4	29.1	61.3	10.7	42.8	15.5	34.2	19.8	30.2-22.1	23.5	13.2
394	Meadow Creek (Sussex, U. Cre.)	38.8	0.12	39	4.4	32.5	60.2	10.6	42.8	15.9	36.0	17.4	33.2-25.4	21.9	18.4
395	Murphy Dome (Tensleep, Penn.)	34.0	1.70	43	10.8	29.3	61.5	11.3	42.5	16.8	33.6	17.8	29.1-21.0	22.6	11.3
396	Oregon Basin (Embar-Tensleep-Madison, Perm. Penn.-Miss.)	20.5	3.25	360	20.5	14.3	59.5	3.3	42.6	14.8	33.8	19.6	27.7-17.9	47.5	6.8
397	Salt Creek (Wall Creek, U. Cre.)	36.6	0.12	43	4.4	27.6	56.9	10.1	42.8	16.4	36.8	18.9	34.0-27.1	26.1	19.2
398	Steamboat Butte (Tensleep, Penn.)	28.2	2.18	66	16.1	19.3	61.0	9.1	44.1	17.0	33.4	20.6	29.5-20.8	33.1	9.4
399	Sussex (Lakota, L. Cre.)	30.0	0.37	38	6.4	31.7	60.0	10.4	42.8	13.6	36.8	19.6	34.2-26.6	21.9	18.2
400	Werts (Tensleep, Penn.)	33.6	1.32	43	10.1	28.5	59.7	10.8	42.5	16.1	33.6	19.9	29.8-19.2	24.3	13.5
401	Winkleman Dome (Phosphoria, Perm.)	25.7	2.59	93	16.8	16.0	57.7	8.4	42.3	15.2	32.8	21.5	28.7-19.5	37.3	9.2

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[1] Geologic age names are abbreviated as follows: Cambrian, Cam.; Cambro-Ordovician, Cam.-Ord.; Cretaceous, Cre.; Lower Cretaceous, L. Cre.; Upper Cretaceous, U. Cre.; Devonian, Dev.; Upper Devonian, U. Dev.; Eocene, Eoc.; Jurassic, Jur.; Miocene, Mio.; Lower Miocene, L. Mio.; Upper Miocene, U. Mio.; Mississippian, Miss.; Oligocene, Olig.; Ordovician, Ord.; Lower Ordovician, L. Ord.; Middle Ordovician, M. Ord.; Pennsylvanian, Penn.; Permian, Perm.; Pliocene, Plio.; Pliocene-Miocene, Plio.-Mio.; Pliocene-Pleistocene, Plio.-Pleist.; Upper Pliocene, U. Plio.; Silurian, Sil.; Pre-Cambrian, Pre-Cam.

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Table A-3. TRACE ELEMENT CONTENT OF UNITED STATES CRUDE OILS

State and Field	Trace Elements, ppm									Analytical Method	Year
	V	Ni	Fe	Ba	Cr	Mn	Mo	Sn	Hg		
ALABAMA											
Toxey	9	14								Emission spectroscopy	1971
Toxey	10	16								Emission spectroscopy	1971
ALASKA											
Kuparuk, Prudhoe Bay	42	13								Emission spectroscopy	1971
Kuparuk, Prudhoe Bay	28	12								Emission spectroscopy	1971
McArthur River, Cook Inlet	nd	nd								Emission spectroscopy	1971
Prudhoe Bay	31	11								Emission spectroscopy	1971
Put River, Prudhoe Bay	16	6								Emission spectroscopy	1971
Redoubt Shoal, Cook Inlet	nd	4								Emission spectroscopy	1971
Trading Bay, Cook Inlet	nd	nd								Emission spectroscopy	1971
ARKANSAS											
Brister, Columbia	nd	nd								Emission spectroscopy	1971
El Dorado, East	12	11								Emission spectroscopy	1971
Schuler	15.2	10.1	1.2	<1	<1	<1	nd	nd		Emission spectroscopy	1961
Smackover	nd	4								Emission spectroscopy	1971
Stephens-Smart	18.5	22.7	6.3	<1	<1	<1	nd	<1		Emission spectroscopy	1961
Tubal, Union	nd	nd								Emission spectroscopy	1971
West Atlanta	<1	<1	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961
CALIFORNIA											
Ant Hill	16.1	66.5	28.5	<1	<1	nd	nd	nd		Emission spectroscopy	1961
Arwin	9.0	28.0								Emission spectroscopy	1956
Bradley Sands	134.5	--								(1)	1958
Cat Canyon	128	75								Emission spectroscopy	1971
Cat Canyon	209	102								Emission spectroscopy	1971
Coalinger	5.1	21.9	5.1	<1	<1	<1	<1	nd		Emission spectroscopy	1961
Coal Oil Canyon	6.0	20.0								Emission spectroscopy	1956
Coles Levee	11.0	31.0								Emission spectroscopy	1956
Coles Levee	2.2	21.6	2.2	<1	<1	nd	<1	nd		Emission spectroscopy	1961
Cuyama	10.0	32.0								Emission spectroscopy	1956
Cymric	30.0	43.0								Emission spectroscopy	1956
Cymric	0.8	2.3	2.0							Emission spectroscopy	1961
Cymric									2.6 2.4 1.9	Emission spectroscopy	1961
Cymric	0.6	1.1	2.0							Emission spectroscopy	1961
Cymric									21.0 14.0 2.9	Emission spectroscopy	1961
Cymric	1.0	2.0	2.0							Emission spectroscopy	1961
Edison	6.0	11.0								Emission spectroscopy	1956
Elk Hills	8.3	38.5	38.5	<1	<1	<1	<1	nd		Emission spectroscopy	1961
Elwood South	nd	11								Emission spectroscopy	1971
Gibson	37	125								X-ray fluorescence	1969
Gote Ridge	188	80								Emission spectroscopy	1971
Helm	14.0	27.0								Emission spectroscopy	1956
Helm	2.5	10.5	2.5	<1	<1	nd	nd	<1		Emission spectroscopy	1961
Huntington Beach	29	104								Emission spectroscopy	1971
Inglewood	125.7	125.7	125.7	<1	1.3	nd	<1	nd		Emission spectroscopy	1961
Kettleman	34.0	35.0	24.0							Colorimetric	1952
Kettleman Hills	11.0	24.0								(1)	1958
Las Flores	106.5	--								(1)	1958
Lompoc	37.6	--								(1)	1958
Lompoc	199	90								Emission spectroscopy	1971
Lost Hills	39.0	8.0								Emission spectroscopy	1956
Midway	82.6	82.6	82.6	1.8	1.8	<1	<1	nd		Emission spectroscopy	1961
Nicolai	246.5	--								(1)	1958
North Belridge	--	107								X-ray fluorescence (inter. std)	1959
North Belridge	--	80								Colorimetric	1959
North Belridge	--	83								Emission spectroscopy	1959
North Belridge	23	83								X-ray fluoresc. (ext. std.)	1960
Orcutt	162.5	--								(1)	1958
Oxnard	403.5	--								(1)	1958
Purisma	218.5	--								(1)	1958
Raisin City	8.0	21.0								Emission spectroscopy	1956

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(1) Not specified.

nd Sought but not detected.

Table A-3 (Continued). TRACE ELEMENT CONTENT OF UNITED STATES CRUDE OILS

State and Field	Trace Element, ppm									Analytical Method	Year
	V	Ni	Fe	Cu	Cr	Mn	Mo	Co	As		
Rio Bravo	--	2.2								X-ray fluorescence (int. std.)	1962
Rio Bravo	--	--	2.6							X-ray fluorescence (int. std.)	1960
Rio Bravo	--	--	2.5							Emission spectroscopy	1960
Russell Ranch	12.0	26.0								Emission spectroscopy	1956
San Joaquin	44.8	--								(1)	1958
Santa Maria	223	97	17							Colorimetric	1952
Santa Maria	202	--								(1)	1958
Santa Maria	180	106								Emission spectroscopy	1956
Santa Maria	280	130								Emission spectroscopy	1960
Santa Maria Valley	207	97								Emission spectroscopy	1971
Santa Maria Valley	240	--								X-ray fluorescence (int. std.)	1960
Santa Maria Valley	280	--								X-ray fluorescence (int. std.)	1960
Santa Maria Valley	176	176	1.7	<1	1.7	<1	4.0	nd		Emission spectroscopy	1961
Signal Hill	28	--								(1)	1958
Signal Hill	25	57								Emission spectroscopy	1956
Tejon Hills	64	46								Emission spectroscopy	1956
Ventura	42	51								Emission spectroscopy	1956
Ventura	49	33	31							Colorimetric	1952
Ventura Avenue	25.2	--								(1)	1958
Wheeler Ridge	7	1.9								Emission spectroscopy	1956
Wilmington	43	61								Emission spectroscopy	1956
Wilmington	41	46	28							Colorimetric	1952
Wilmington	53	51								Emission spectroscopy	1971
Wilmington	--	53								X-ray fluorescence (int. std.)	1959
Wilmington	--	60								X-ray fluorescence (int. std.)	1959
Wilmington	46	60								Emission spectroscopy	1960
Wilmington	36.0	84	36	3.6	<1	nd	1	nd		Emission spectroscopy	1961
COLORADO											
Badger Creek	<1	<1	<1	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Badger Creek	<1	<1	<1	<1	nd	<1	<1	<1		Emission spectroscopy	1961
Grampo	<1	<1	<1	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Gramp	<1	<1	<1	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Hiawatha	<1	<1	<1	<1	<1	<1	nd	<1		Emission spectroscopy	1961
Moffat Dome	<1	<1	<1	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Rangely	2.7	<1	<1	<1	<1	<1	nd	<1		Emission spectroscopy	1961
Rangely	<1	<1	6.6	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Rangely	<1	<1	2.7	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Seep	0.24	6.70								Emission spectroscopy	1956
White River Area	<1	<1	96.0	<1	<1	2.2	nd	2.2		Emission spectroscopy	1961
FLORIDA											
Joy	nd	1								Emission spectroscopy	1971
ILLINOIS											
Loudon	1.22	0.62	0.57							Emission spectroscopy	1952
Loudon	0.56	--								(1)	1958
KANSAS											
Brewster	2.1	1.3	<1	<1	<1	nd	nd	nd		Emission spectroscopy	1961
Brewster	<1	3.9	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961
Brock	1	2.4	10.2	<1	<1	<1	<1	nd		Emission spectroscopy	1961
Coffeyville	3.8	1.2	7.2	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Cunningham	44.2	9.9	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961
Cunningham	24.0	24.0	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961
Iola	15.6	9.0	3.9	2	<1	<1	nd	nd		Emission spectroscopy	1961
Iola	4.5	4.5	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961
"Kansas-1"	--	>5							<.021	Emission spectroscopy	1966
"Kansas-2"	--	>21							<.08	Emission spectroscopy	1966
McLouth	<1	6.3	<1	<1	<1	<1	<1	nd		Emission spectroscopy	1961
Otis Albert	21.3	6.0	<1	<1	<1	<1	<1	nd		Emission spectroscopy	1961
Otis Albert	39.0	9.1	9.1	<1	<1	<1	<1	<1		Emission spectroscopy	1961
Pawnee Rock	12.3	3.4	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961
Rhodes	145	--								X-ray fluorescence (int. std.)	1960
Rhodes	165	--								Emission spectroscopy	1960
Rhodes	133	--								X-ray fluorescence (int. std.)	1960
Rhodes	--	36								X-ray fluorescence (int. std.)	1960
Rhodes	--	38								Emission spectroscopy	1960
Rhodes	--	32								X-ray fluorescence (int. std.)	1959
Solomon	30	7	<1	<1	<1	<1	nd	nd		Emission spectroscopy	1961

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(1) Not specified

nd Sought but not detected

Table A-3 (Continued). TRACE ELEMENT CONTENT OF UNITED STATES CRUDE OIL[1]

	Trace Element, ppm										
State and Field	V	Ni	Fe	Ba	Cr	Mn	Mo	Sn	As	Analytical Method	Year
LOUISIANA											
Bay Marchand	nd	2								Emission spectroscopy	1971
Colquitt, Clairborne	nd	nd								Emission spectroscopy	1971
Colquitt, Clairborne	nd	nd								Emission spectroscopy	1971
Colquitt, Calirborne (Smackover B)	nd	nd								Emission spectroscopy	1971
Delta (west) Offshore, Block 117	nd	2								Emission spectroscopy	1971
Delta (West) Block 27	nd	2								Emission spectroscopy	1971
Delta (West) Block 41	nd	2								Emission spectroscopy	1971
Eugene Island, Offshore, Block 276	4	nd								Emission spectroscopy	1971
Eugene Island, Offshore, Block 238	nd	nd								Emission spectroscopy	1971
Lake Washington	nd	4								Emission spectroscopy	1971
Main Pass, Block 6	nd	3								Emission spectroscopy	1971
Main Pass, Block 41	nd	1								Emission spectroscopy	1971
Olla	<1	5.56	0.07							Emission spectroscopy	1952
Ship Shoal, Offshore, Block 176	nd	nd								Emission spectroscopy	1971
Ship Shoal, Offshore, Block 176	nd	nd								Emission spectroscopy	1971
Ship Shoal, Block 208	nd	2								Emission spectroscopy	1971
Shongaloo, N. Red Rock	nd	nd								Emission spectroscopy	1971
South Pass, Offshore, Block 62	nd	4								Emission spectroscopy	1971
Timbalier, S., Offshore, Block 34	nd	nd								Emission spectroscopy	1971
MICHIGAN											
Trent	--	0.23								Emission spectroscopy	1956
MISSISSIPPI											
Baxterville, Lamar and Marion	40	15								Emission spectroscopy	1971
Heidelberg	15.35	6.02	1.78							Emission spectroscopy	1952
Mississippi	--	.7							<.003	Emission spectroscopy	1966
Tallhalla Creek, Smith	nd	nd								Emission spectroscopy	1971
Tallhalla Creek, Smith	nd	nd								Emission spectroscopy	1971
Tallhalla Creek, Smith (Smackover)	nd	nd								Emission spectroscopy	1971
Tingley, Yazoo	7	5								Emission spectroscopy	1971
MONTANA											
Bell Creek	nd	2								Emission spectroscopy	1971
Big Wall	24	13.2		<1	<1	<1		<1	nd	Emission spectroscopy	1961
Soap Creek	132	13.2		<1	<1	<1		<1	nd	Emission spectroscopy	1961
NEW MEXICO											
Rattlesnake	<1	<1	<1	<1	<1	<1		<1	nd	Emission spectroscopy	1961
Rattlesnake	<1	<1	<1	<1	<1	<1		<1	nd	Emission spectroscopy	1961
Table Mesa	<1	<1	9.9	<1	<1	<1		<1	<1	Emission spectroscopy	1961
OKLAHOMA											
Allurve (Nowata)	<1	<1	1.4	6.0	<1	<1		<1	<1	Emission spectroscopy	1961
Allurve (Nowata)	1.1	1.2	51.0	11.9	<1	<1		nd	<1	Emission spectroscopy	1961
Allurve (Nowata)	<1	6.0	1.4	6.0	<1	<1		<1	<1	Emission spectroscopy	1961
Bethel	--	0.85								Emission spectroscopy	1956
Burbank	nd	nd								Emission spectroscopy	1971
Cory	0.15	0.65								Emission spectroscopy	1956
Chelsea (Nowata)	1.4	1.4	27.0	6.3	<1	<1		nd	nd	Emission Spectroscopy	1962
Chelsea (Nowata)	<1	<1	6.0	<1	<1	<1		<1	<1	Emission Spectroscopy	1961
Chelsea (Nowata)	<1	<1	<1	3.0	<1	<1		nd	<1	Emission Spectroscopy	1961
Chevarha	0.12	0.70								Emission spectroscopy	1956
Chevarha	0.14	0.95								Emission spectroscopy	1956
Chevarha	0.21	0.36								Emission spectroscopy	1956
Chevarha	0.36	4.10								Emission spectroscopy	1956
Cromwell	0.23	0.80								Emission spectroscopy	1956
Cromwell	0.11	0.23								Emission spectroscopy	1956
Cromwell	0.10	0.23								Emission spectroscopy	1956
Cromwell	--	0.27								Emission spectroscopy	1956
Cromwell	0.10	0.42								Emission spectroscopy	1956
Cromwell	--	0.23								Emission spectroscopy	1956
Dill	0.23	2.10								Emission spectroscopy	1956
Dover, Southeast	nd	nd								Emission spectroscopy	1971
Dustin	--	0.36								Emission spectroscopy	1956
E. Lindsay	--	0.10								Emission spectroscopy	1956
E. Seminole	0.23	0.46								Emission spectroscopy	1956
E. Teager	--	0.12								Emission spectroscopy	1956
Fish	--	0.23								Emission spectroscopy	1956
Glen Pool	--	--	5.0							X-ray fluorescence (int. std.)	1960

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(1) Not specified

nd Sought but not detected

Table A-3 (Continued). TRACE ELEMENT CONTENT OF UNITED STATES CRUDE OILS

State and Field	Trace Element, ppm V	Ni	Fe	Cu	Cr	Mn	Pb	Zn	Analytical Method	Year
Grief Creek	0.10	0.42							Emission spectroscopy	1956
Hawkins	2.10	8.50							Emission spectroscopy	1956
Hawkins	0.72	3.50							Emission spectroscopy	1956
Horne Corner	--	0.70							Emission spectroscopy	1956
Katie	0.17	0.52							Emission spectroscopy	1956
Katie	0.48	1.60							Emission spectroscopy	1956
Katie	0.29	1.00							Emission spectroscopy	1956
Katie	0.26	1.00							Emission spectroscopy	1956
Kendrick	<1	<1	<1	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Konawa	0.10	0.65							Emission spectroscopy	1956
Laffoon	44.0	20.2	1.5	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Little River	0.17	1.10							Emission spectroscopy	1956
Middle Gilliland	<1	<1	<1	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Naval Reserve	<1	<1	<1	<1	<1	<1	nd	nd	Emission spectroscopy	1961
New England	<1	<1	<1	nd	<1	<1	nd	nd	Emission spectroscopy	1961
N. Dill	0.13	1.45							Emission spectroscopy	1956
N. E. Castle Ext.	0.29	1.50							Emission spectroscopy	1956
N. E. Elmore	0.15	0.60							Emission spectroscopy	1956
N. E. Elmore	0.17	0.70							Emission spectroscopy	1956
N. Okemah	0.11	0.70							Emission spectroscopy	1956
N. W. Horne Corner	—	0.10							Emission spectroscopy	1956
Olympic	0.88	2.40							Emission spectroscopy	1956
Osage City	2.9	1.6	6.9	nd	<1	<1	nd	nd	Emission spectroscopy	1961
S. W. Maysville	1.36	2.10							Emission spectroscopy	1956
S. W. Maysville	0.25	1.10							Emission spectroscopy	1956
Tatums	—	57							X-ray fluorescence	1959
Tatums	--	56							Emission spectroscopy	1959
Tatums	148	71							X-ray fluorescence (ext. std.)	1960
Weleetka	--	0.10							Emission spectroscopy	1956
W. Holdenville	0.13	0.46							Emission spectroscopy	1956
W. Wewoka	0.14	0.42							Emission spectroscopy	1956
Wewoka	—	0.15							Emission spectroscopy	1956
Wewoka Lake	0.33	0.95							Emission spectroscopy	1956
Wewoka Lake	0.15	0.30							Emission spectroscopy	1956
Wewoka Lake	0.18	0.27							Emission spectroscopy	1956
Wildhorse	2.6	3	<1	nd	nd	<1	nd	nd	Emission spectroscopy	1961
Wynona	<1	<1	1.8	<1	<1	<1	nd	<1	Emission spectroscopy	1961
Wynona	<1	<1	<1	<1	nd	<1	nd	<1	Emission spectroscopy	1961
TEXAS										
Anahuac	0.2	1.1	—						Emission spectroscopy	1958
Brantley-Jackson, Hopkins	nd	nd	--						Emission spectroscopy	1971
Brantley-Jackson, Smackover	nd	nd	—						Emission spectroscopy	1971
Conroe	0.008	<1	0.81						Chemical (V); emission (Ni)	1952
East Texas	4	3	—						Emission spectroscopy	1971
East Texas	1.2	0.88	0.51						Emission spectroscopy	1952
East Texas	1.05	1.69	--						Colorimetric	1952
East Texas	1.2	1.7	..2						Colorimetric	1952
Edgewood, Van Zandt	nd	nd	--						Emission spectroscopy	1971
Finley	2.6	2	5.7	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Jackson	0.9	1.8	4.4						Colorimetric	1952
Lake Trammel, Nolan			—						Emission spectroscopy	1971
Mirando	1.4	1.9	7.6						Colorimetric	1952
Panhandle, Carson	8	3	--						Emission spectroscopy	1971
Panhandle, Hutchinson	6	5	—						Emission spectroscopy	1971
Panhandle, West Texas	8.4	—	--						(1)	1952
Refugio	0.68	0.70	0.34						Chemical	1952
Refugio, Light	0.56	—	—						(1)	1958
Salt Flat	8.3	1.63	1.71						Chemical	1952
Scurry County	0.8	1.0	3.4						Colorimetric	1952
Sweden	0.8	0.6	--						Emission spectroscopy	1958
Talco	8.8	2.57	2.06						Chemical	1952
Talco	6.16	--	--						(1)	1958
Wasson	15	nd	--						Emission spectroscopy	1971
West Texas	23	5	--						X-ray fluoresc. spectro. (ext. std.) or emission spectroscopy	1960
West Texas	6.7	--	--						(1)	1952
West Texas	6.3	--	--						Emission spectroscopy	1956
West Texas	11.8,	3.8	--						Emission spectroscopy	1958
West Texas	8.5	6.2							Emission spectroscopy	1958
West Texas	8.96	--	--						(1)	1958
West Texas	7.9	4.8	5.1						Colbrimetric	1952
West Texas (Imogene)	8.5	1.73	0.88						Chemical	1952
Yates-Pecos	7.8	2.6	0.11						Chemical	1952

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(1) Not specified

nd Sought but not detected

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Table A-3 (Continued). TRACE ELEMENT CONTENT OF UNITED STATES CRUDE OILS

State and Field	Trace Element, ppm								Analytical Method	Year
	V	Ni	Fe	Ba	Cr	Mn	Mo	Sn		
UTAH										
Duchesne	<1	<1	3.9	3.9	<1	<1	<1	<1	Emission spectroscopy	1961
Duchesne	<1	<1	1.4	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Duchesne County	<1	12.3	12.3	2.9	<1	<1	nd	nd	Emission spectroscopy	1961
Red Wash	nd	nd	--						Emission spectroscopy	1971
Red Wash	nd	nd	--						Emission spectroscopy	1971
Roosevelt	<1	3.2	<1	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Roosevelt	<1	5.4	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Virgin	14.4	14.4	3.6	<1	<1	<1	nd	<1	Emission spectroscopy	1961
Virgin	8.1	8.1	1.9	<1	<1	<1	nd	<1	Emission spectroscopy	1961
West Pleasant Valley	11.4	57	1140.0	26.6	1.1	11.4	2.7		Emission spectroscopy	1961
Wildcat	0.14	7.5							Emission spectroscopy	1956
WYOMING										
Beaver Creek	nd	nd							Emission spectroscopy	1971
Big Horn Mix	15.97	3.6	0.8						Emission spectroscopy	1952
Bison Basin	1.1	2.7	<1	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Circle Ridge	48	11.2	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Corral Creek	59	11	--						Emission spectroscopy	1971
Crooks Gap	2.1	2.2	1.0	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Dallas	66	15.4	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Dallas	66	66	1.5	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Derby	39	39	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Elk Basin	38	9.2	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Elk Basin	8.4	2	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Garland	36	24	1.6	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Grass Creek	106.4	28.9	1.1	<1	<1	<1	<1	nd	Emission spectroscopy	1951
Half Moon	98.6	27.8	1.7	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Half Moon	50.6	<1	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Hamilton Dome	106.4	26.6	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Hamilton Dome	55.2	8.6	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Hamilton Dome	106.4	24.3	2.7	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Little Mo	83	16	--						Emission spectroscopy	1971
Lost Soldier	<1	<1	<1	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Lost Soldier	<1	<1	<1	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Lost Soldier	<1	<1	<1	<1	<1	<1	<1	<1	Emission spectroscopy	1961
Mitchell Creek	72.0	72.0	7.2	<1	<1	<1	<1	nd	Emission spectroscopy	1961
North Oregon Basin	77.0	22.4	1.0	<1	<1	<1	<1	nd	Emission spectroscopy	1961
North Oregon Basin	72.0	14.8	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
North Oregon Basin	60.0	11.5	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Oil Mountain	144.0	33.6	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Pilot Butte	45.0	10.5	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Pilot Butte	24.0	5.6	<1	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Pine Ridge	nd	nd	--						Emission spectroscopy	1971
Prescott No. 3	21.0	7.1	--						(1)	1959
Recluse	nd	nd	--						Emission spectroscopy	1971
Roelis	88	15	--						Emission spectroscopy	1971
Salt Creek	86.0	8.4	<1	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Salt Creek	1.4	1.4	<1	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Salt Creek	<1	<1	23.4	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Salt Creek	<1	3.9	3.9	<1	<1	<1	nd	nd	Emission spectroscopy	1961
Shull Creek	--	0.42							Emission spectroscopy	1956
South Casper Creek	12.9	3.0	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
South Fork	21.9	21.9	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
South Spring Creek	102.0	102.0	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
South Spring Creek	117.0	27.3	<1	<1	<1	<1	<1	nd	Emission spectroscopy	1961
Steamboat Butte	29.1	6.79	<1	<1	<1	<1	1	nd	Emission spectroscopy	1961
Washakie	74.0	25.0	--						(1)	1934
Winkleman Dome	48.0	11.2	1	<1	<1	<1	<1	nd	Emission spectroscopy	1961

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(1) Not specified

nd Sought but not detected.

Source: Magee, E. M., H. J. Hall, and G. M. Varga, Jr., Potential Pollutants in Fossil Fuels, PB 225 039, EPA-R2-73-249, Contract No. 68-02-0629, Linden, N.J., Esso Research & Engineering Co., 1973.

Table A-4. SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	1971 Production (Thousands of Barrels)*
ALABAMA			
Citronelle	0.38	0.02	6,390
ALASKA			
Granite Point	0.02	0.039	5,552
McArthur River	0.16	0.160	40,683
Middle Ground Shoal	0.05	0.119	11,277
Prudhoe Bay (North Slope)	1.07	0.23	1,076
Swanson River	0.16	0.203	11,709
APPALACHIAN			
Allegany	0.12	0.028	388
Bradford	0.11	0.010	2,470
ARKANSAS			
Magnolia	0.90	0.02	850
Schuler and East	1.55	0.112	800
Smackover	2.10	0.08	2,800
CALIFORNIA			
SAN JOAQUIN VALLEY			
Belridge South	0.23	0.773	9,211
Buena Vista	0.59	--	5,429
Coalinga	0.43	0.303	7,866
Coalinga Nose	0.25	0.194	4,752
Coles Levee North	0.39	0.309	1,006
Cuyama South	0.42	0.337	2,034
Cymric	1.16	0.63	3,345
Edison	0.20	0.446	1,417
Elk Hills	0.68	0.472	951
Fruitvale	0.93	0.527	1,109
Greeley	0.31	0.266	761
Kern Front	0.85	0.676	3,440
Kern River	1.19	0.604	25,542
Kettleman North Dome	0.40	0.212	840
Lost Hills	0.33	0.094	2,328
McKittrick - Main Area	0.96	0.67	5,348
Midway Sunset	0.94	0.42	33,583
Mount Poso	0.68	0.475	1,378
Rio Bravo	0.35	0.158	425
COASTAL AREA			
Carpenteria Offshore	--	--	5,295
Cat Canyon West	5.07	0.54	2,705
Dos Cuadras	--	--	27,739
Elwood	--	--	108

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* Oil and Gas Journal, January 31, 1972, pp. 95-100.

Table A-4 (Continued). SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	1971 Production (Thousands of Barrels)*
Orcutt	2.48	0.525	2,173
Rincon	0.40	0.48	4,580
San Ardo	2.25	0.913	9,939
Santa Ynez***	--	--	--
Santa Maria Valley	4.99	0.56	1,966
South Mountain	2.79	--	1,962
Ventura	0.94	0.413	10,188
LOS ANGELES BASIN			
Beverly Hills	2.45	0.612	8,400
Brea Olinda	0.75	0.525	4,228
Coyote East	0.95	0.336	864
Coyote West	0.82	0.347	2,436
Dominguez	0.40	0.360	1,717
Huntington Beach	1.57	0.648	16,249
Inglewood	2.50	0.640	3,992
Long Beach	1.29	0.55	3,183
Montebello	0.68	0.316	740
Richfield	1.86	0.575	1,910
Santa Fe Springs	0.33	0.271	953
Seal Beach	0.55	0.394	1,468
Torrance	1.84	0.555	1,338
Wilmington	1.44	0.65	72,859
COLORADO			
Rangely	0.56	0.073	10,040
FLORIDA			
Jay	0.32	0.002	370
ILLINOIS			
Clay City	0.19	0.082	4,650
Dale	0.15	0.080	690
Loudon	0.27	0.097	4,420
New Harmony	0.23	0.158	2,740
Salem	0.17	0.102	3,360
KANSAS			
Bemis-Shutts	0.57	0.162	2,590
Chase-Silica	0.44	0.13	1,600
Eldorado	0.18	0.085	1,500
Hall-Gurney	0.34	0.108	2,480
Kraft-Prusa	0.27	0.171	3,200
Trapp	0.41	0.076	1,930
LOUISIANA			
NORTH			
Black Lake	--	--	--
Caddo-Pine Island	0.37	0.026	3,500
Delhi	0.82	0.053	5,870
Haynesville (Ark.-La.)	0.66	0.022	2,730
Homer	0.83	0.081	330
Lake St. John	0.17	--	1,170
Rodessa (La.-Tex.)	0.46	0.032	900

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* Oil and Gas Journal, January 31, 1972, pp. 95-100.

Table A-4 (Continued). SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production (Thousands of Barrels)*
OFFSHORE			
Bay Marchand Block 2 (Incl. onshore)	0.46	0.11	30,806
Eugene Island Block 126	0.15	0.030	5,621
Grand Isle Block 16	0.18	0.04	21,681
Grand Isle Block 43	--	--	22,776
Grand Isle Block 47	0.23	0.04	4,271
Main Pass Block 35	0.19	0.071	3,504
Main Pass Block 41	0.16	0.025	18,469
Main Pass Block 69	0.25	0.098	12,775
Ship Shoal Block 208	0.38	0.02	10,038
South Pass Block 24 (Incl. onshore)	0.26	0.068	20,330
South Pass Block 27	0.18	0.049	21,425
Timbalier S. Block 135	0.66	0.088	13,578
Timbalier Bay	--	--	
(Incl. onshore)	0.33	0.081	30,988
West Delta Block 30	0.33	0.09	26,390
West Delta Block 73	--	--	15,987
SOUTH, ONSHORE			
Avery Island	0.12	--	3,400
Bay De Chene	0.27	0.060	6,643
Bay St. Elaine	0.39	0.04	7,775
Bayou Sale	0.16	--	5,293
Black Bay West	0.19	0.04	9,892
Caillou Island (Incl. offshore)	0.23	0.04	31,828
Cote Blanche Bay West	0.16	0.033	15,658
Cote Blanche Island	0.10	0.01	8,797
Delta Farms	0.26	0.055	1,278
Garden Island Bay	0.22	0.06	16,096
Golden Meadow	0.18	--	2,738
Grand Bay	0.31	--	6,680
Hackberry East	0.30	0.054	2,226
Hackberry West	0.29	--	3,760
Iowa	0.20	0.039	876
Jennings	0.26	--	292
Lafitte	0.30	--	10,877
Lake Barre	0.14	0.02	7,592
Lake Pelto	0.21	0.035	4,891
Lake Salvador	0.14	0.02	4,380
Lake Washington (Incl. offshore)	0.37	0.146	10,913
Leeville	0.20	0.019	4,343
Paradis	0.23	--	1,898
Quarantine Bay	0.27	0.061	7,117
Romere Pass	0.30	--	3,759
Venice	0.24	--	5,475
Vinton	0.34	0.044	2,299
Weeks Island	0.19	--	10,183
West Bay	0.27	0.071	9,563

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* Oil and Gas Journal, January 31, 1972, pp. 95-100.

Table A-4 (Continued). SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	1971 Product (Thousands of Barrels)*
MISSISSIPPI			
Baxterville	2.71	0.111	9,300
Heidelberg	3.75	0.112	3,450
Tinsley	1.02	0.08	2,450
MONTANA			
Bell Creek	0.24	0.13	5,950
Cut Bank	0.80	0.055	5,180
NEW MEXICO			
Caprock and East	0.17	0.034	905
Denton	0.17	0.014	2,350
Empire Abo	0.27	0.014	9,520
Eunice	1.14	0.071	1,330
Hobbs	1.41	0.08	5,700
Maljamar	0.55	0.062	6,040
Monument	1.14	0.071	3,720
Vacuum	0.95	0.075	17,030
NORTH DAKOTA			
Beaver Lodge	0.24	0.019	3,140
Tioga	0.31	0.016	1,790
OKLAHOMA			
Allen	0.70	0.21	2,920
Avant	0.18	--	365
Bowlegs	0.24	0.140	2,260
Burbank	0.24	0.051	5,240
Cement	0.47	0.152	2,370
Cushing	0.22	0.08	4,300
Earlsboro	0.47	--	765
Edmond West	0.21	0.045	730
Eola-Robberson	0.35	0.115	4,850
Fitts	0.27	--	1,420
Glenn Pool	0.31	0.096	2,480
Golden Trend	0.15	0.15	12,330
Healdton	0.92	0.15	4,600
Hewitt	0.65	0.148	5,660
Little River	0.28	0.065	440
Oklahoma City	0.16	0.079	1,750
Seminole, Greater	0.30	0.016	1,640
Sho-Vel-Tum	1.18	0.27	36,500
Sooner Trend	--	--	15,240
St. Louis	0.11	0.04	1,350
Tonkawa	0.16	0.033	290

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* Oil and Gas Journal, January 31, 1972, pp. 95-100.

Table A-4 (Continued). SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	1971 Production (Thousands of Barrels)*
TEXAS			
DISTRICT 1			
Big Wells	--	--	5,840
Darst Creek	0.78	0.075	1,971
Luling-Branyon	0.86	0.110	1,679
DISTRICT 2			
Greta	0.17	0.038	3,577
Refugio	0.11	0.027	657
Tom O'Connor	0.17	0.038	23,360
West Ranch	0.14	0.029	17,009
DISTRICT 3			
Anahuac	0.23	0.041	9,052
Barbers Hill	0.27	0.06	766
Conroe	0.15	0.022	12,994
Dickison-Gillock	0.82	0.014	2,920
Goose Creek and East	0.13	0.028	1,095
Hastings E&W	0.20	0.03	17,191
High Island	0.26	0.048	2,081
Hull-Merchant	0.35	0.081	1,643
Humble	0.46	0.097	1,241
Liberty South	0.14	0.044	949
Magnet Withers	0.19	0.033	3,869
Old Ocean	0.14	0.029	1,132
Raccoon Bend	0.19	0.048	2,409
Sour Lake	0.14	0.016	1,058
Spindletop	0.15	0.03	328
Thompson	0.25	0.029	12,885
Webster	0.21	0.046	16,206
West Columbia	0.21	0.055	1,351
DISTRICT 4			
Agua Duke-Stratton	<.1	0.015	2,518
Alazan North	0.04	0.014	3,723
Borregas	<.1	0.029	4,818
Government Wells N.	0.22	0.043	511
Kelsey	0.13	0.008	6,059
La Gloria and South	<.1	0.008	936
Plymouth	0.15	0.049	986
Seeligson	<.1	0.015	6,424
Tijerina-Canales-Blucher	<.1	0.010	5,986
White Point East	0.13	0.02	1,606
DISTRICT 5			
Mexia	0.20	0.048	109
Powell	0.31	0.054	109
Van and Van Shallow	0.8	0.039	12,337

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* Oil and Gas Journal, January 31, 1972, pp. 95-100.

Table A-4 (Continued). SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	1971 Production (Thousands of Barrels)*
DISTRICT 6			
East Texas	0.32	0.066	71,139
Fairway	0.24	--	14,271
Hawkins	2.19	0.076	29,054
Neches	0.13	0.083	3,942
New Hope	0.46	0.007	292
Quitman	0.92	0.036	3,103
Talco	2.98	--	4,380
DISTRICT 7-C			
Big Lake	0.26	0.071	474
Jameson	<.1	0.034	1,387
McCamey	2.26	0.139	985
Pegasus	0.73	0.200	4,052
DISTRICT 8			
Andector	0.22	0.033	5,694
Block 31	0.11	0.032	6,242
Cowden North	1.89	0.095	9,782
Cowden South, Foster, Johnson	1.77	0.127	14,198
Dollarhide	0.39	0.074	7,592
Dora Roberts	<.1	0.023	3,066
Dune	3.11	0.111	11,425
Emma and Triple N	<.1	0.025	3,030
Fuhrman-Mascho	2.06	0.085	1,935
Fullerton	0.37	0.041	6,607
Goldsmith	1.12	0.079	20,951
Headlee and North	<.1	0.083	1,460
Hendrick	1.73	0.094	766
Howard Glass[illegible]k	1.92	0.096	6,606
Iatan East	1.47	0.120	3,687
Jordan	1.48	0.10	3,212
Kermit	0.94	0.092	2,007
Keystone	0.57	0.042	8,322
McElroy	2.37	0.080	9,015
Means	1.75	0.205	7,921
Midland Farms	0.13	0.080	6,059
Penwell	1.75	0.205	2,044
Sand Hills	2.06	0.085	6,606
Shafter Lake	0.25	0.041	2,956
TXL	0.36	0.067	4,854
Waddell	1.69	0.098	4,453
Ward South	1.12	0.08	803
Ward Estes North	1.17	0.107	10,184
Yates	1.54	0.150	13,359

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* *Oil and Gas Journal*, January 31, 1972, pp. 95-100.

Table A-4 (Continued). SULFUR AND NITROGEN CONTENT OF THE GIANT U.S. OIL FIELDS

State/Region and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	1971 Production (Thousands of Barrels)*
DISTRICT 8-A			
Cogdell Area	0.38	0.063	14,235
Diamond M	0.20	0.131	7,373
Kelly-Snyder	0.29	0.066	52,487
Levelland	2.12	0.136	9,746
Prentice	2.64	0.117	5,913
Robertson	1.37	0.100	2,774
Russell	0.77	0.078	4,234
Salt Creek	0.57	0.094	9,271
Seminole	1.98	0.106	9,125
Slaughter	2.09	--	35,515
Spraberry Trend	0.18	0.173	18,688
Wasson	1.14	0.065	51,210
DISTRICT 9			
KMA	0.31	0.068	2,920
Walnut Bend	0.17	0.05	3,942
DISTRICT 10			
Panhandle	0.55	0.067	14,235
UTAH			
Greater Aneth	0.20	0.059	7,660
Greater Redwash	0.11	0.255	5,800
WYOMING			
Elk Basin (Mont.-Wyo.)	1.78	0.185	14,380
Garland	2.99	0.290	3,500
Grass Creek	2.63	0.311	3,760
Hamilton Dome	3.04	0.343	4,500
Hilight	--	--	11,300
Lance Creek	0.10	0.055	325
Lost Soldier	1.21	0.076	4,820
Oregon Basin	3.44	0.356	12,260
Salt Creek	0.23	0.109	11,750

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* Oil and Gas Journal, January 31, 1972, pp. 95-100.

Source: Magee, E. M., H. J. Hall, and G. M. Varga, Jr., Potential Pollutants in Fossil Fuels, PB 225 039, EPA-R2-73-249, Contract No. 68-02-0629, Linden, N.J., Esso Research and Engineering Co., 1973.

Table A-5. SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U.S.

NORTH AMERICA Province and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Canada			
Acheson, Alta.	0.46	--	9,400
Bantry, Alta.	2.41	--	6,900
Bonnie Glen, Alta.	0.32	--	36,800
Boundary Lake, B.C.	0.72	--	27,700
Coleville, Sask.	2.62	0.126	4,700
Daly, Manitoba	0.18	--	1,400
Dollard, Sask.	2.18	--	8,800
Excelsior, Alta.	0.71	0.027	1,600
Fenn - Big Valley, Alta.	1.89	--	19,600
Fosterton-Dollard, Sask.	2.91	0.120	7,600
Gilby, Alta.	0.12	--	5,300
Golden Spike, Alta.	0.37	--	37,400
Harmattan, East, Alta.	0.37	--	6,000
Harmattan-Eklton, Alta.	0.44	--	4,500
Innisfail, Alta.	0.58	--	5,500
Joarcam, Alta.	0.13	--	5,900
Joffre, Alta.	0.56	--	6,600
Kaybob, Alta.	0.04	--	10,900
Leduc, Alta.	0.53	0.016	16,700
Lloydminster, Alta.	3.67	--	2,200
Midale, Sask.	2.24	--	11,700
North Premier, Sask.	2.92	--	6,300
Pembina, Alta.	0.22	--	140,000
Redwater, Alta.	0.22	0.041	58,000
Steelman, Sask.	0.73	--	28,200
Stettler, Alta.	1.59	0.055	3,200
Sturgeon Lake, S., Alta.	0.85	--	11,700
Swan Hills, Alta.	0.46	0.034	76,900
Taber, East, Alta.	3.08	--	4,500
Taber, West, Alta.	2.55	--	
Turner Valley, Alta.	0.34	--	2,900
Virden-Roselea, Man.	1.43	--	3,700
Virden-North Scallion, Man.	1.47	--	7,500
Wainwright, Alta.	2.60	--	10,800
Westerose, Alta.	0.25	--	9,400
West Drumheller, Alta.	0.51	--	1,900
Weybum, Sask.	1.89	--	33,300
Wizard Lake, Alta.	0.24	0.023	27,600

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Table A-5 (Continued). SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U S.

SOUTH AMERICA

Field and State	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Venezuela			
Aguasay, Monagas	0.82	--	14,800
Bachaquero, Zulia	2.65	0.377	778,900
Boca, Anzoategui	0.89	0.178	6,100
Boscan, Zulia	5.54	0.593	68,400
Cabimas, Zulia	1.71	0.249	82,000
Caico Seco, Anzoategui	0.13	--	4,200
Centro del Lago, Zulia	1.42	--	132,200
Ceuta, Zulia	1.36	--	63,800
Chimire, Anzoategui	1.07	0.119	17,100
Dacion, Anzoategui	1.29	0.274	10,900
El Roble, Anzoategui	0.10	0.001	1,000
Guara, Anzoategui	2.95	0.314	26,900
Guario, Anzoategui	0.13	0.003	1,100
Inca, Anzoategui	--	0.223	9,500
La Ceibita, Anzoategui	0.41	0.055	14,300
Lago Medio, Zulia	1.16	--	58,100
Lagunillas, Zulia	2.15	0.319	940,100
Lama, Zulia	1.47	0.203	320,000
La Paz, Zulia	1.29	--	23,500
Leona, Anzoategui	1.38	--	11,900
Mapiri, Anzoategui	0.54	0.058	2,800
Mara, Zulia	1.16	0.116	10,100
Mata, Anzoategui	1.09	0.238	55,800
Mene Grande, Zulia	2.00	--	12,200
Mercy, Anzoategui	2.52	0.429	27,500
Nipa, Anzoategui	0.38	--	29,200
Oficina, Anzoategui	0.59	0.202	48,100
Oritupano, Monagas	1.89	--	14,500
Oscurote, Anzoategui	1.19	--	11,400
Pilon, Monagas	2.11	0.360	23,900
Pradera, Anzoategui	0.75	0.033	700
Quiriquire, Monagas	1.33	0.252	22,000
Ruiz, Guarico	1.05	0.161	600
San Joaquin, Anzoategui	0.14	0.036	2,300
Santa Ana, Anzoategui	0.42	--	7,000
Santa Rosa, Anzoategui	0.09	0.006	34,700
Sibucara, Zulia	0.82	0.074	2,000
Silvestre, Barinas	1.17	0.261	12,200
Sinco, Barinas	1.38	0.284	28,400
Soto, Anzoategui	0.52	0.159	10,000
Santa Barbara, Monagas	0.88	0.125	6,100
Tacat, Monagas	1.55	--	3,500
Taman, Guarico	0.14	0.025	400
Temblador, Monagas	0.83	0.338	5,300
Tia Juana, Zulia	1.70	0.269	373,000
Tucupita, Amacuro	1.05	0.312	3,700
Yopales, Anzoategui	1.15	0.275	15,700
Zapatos, Anzoategui	0.48	0.075	19,300

Table A-5 (Continued). SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U.S.

SOUTH AMERICA (Cont'd) Country and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Colombia			
Casabe	1.07	--	7,500
Colorado	0.25	--	900
Galan	1.11	--	1,300
Infantas	0.88	--	4,500
La Cira	0.96	--	17,200
Payoa	0.83	0.147	8,200
Rio Zulia	0.32	--	23,700
Tibu	0.71	--	12,900
Bolivia			
Camiri	0.02	--	2,800
Chile			
Cerro Manatiales	0.05	--	--

Table A-5 (Continued). SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U.S.

MIDDLE EAST

Country and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Saudi Arabia and Neutral Zone			
Abqaiq	2.03	0.105	892,500
Abu Hadriya	1.69	--	103,700
Abu Sa'Fah	2.61	0.232	82,900
Berri	2.24	0.206	155,900
Dammam	1.47	--	21,600
Fadhili	1.25	0.029	47,900
Ghawar	1.89	0.107	2,057,900
Khafji	2.99	0.159	--
Khursaniya	2.53	0.093	74,300
Khurais	1.73	0.307	22,300
Manifa	2.75	0.338	5,100
Qatif	2.55	0.109	95,100
Safaniya	2.88	0.126	791,400
Wafra	3.91	0.145	141,000
Abu Dhabi			
Bu Hasa I	0.74	0.032	--
Bu Hasa II	0.77	0.031	--
Habshan	0.71	0.026	--
Murban-Bab-Bu Hasa	0.62	0.028	564,100
Iran			
Agha Jari	1.41	0.015	848,000
Cyrus	3.68	0.300	24,000
Darius	2.44	0.089	100,000
Gach Saran	1.57	0.226	882,000
Haft Kel	1.20	--	45,000
Naft-i-Shah	0.76	--	10,000
Sassan	2.06	0.082	137,000
Kuwait			
Burgan	2.58	0.122	2,950,000
Magwa-Ahmadi	2.21	0.125	
Minagish	2.12	0.103	
Raudhatain	2.13	0.102	
Sabriyah	1.62	0.096	
Iraq			
Bai Hassan	1.36	0.28	57,000
Kirkuk	1.93	--	1,097,000
Rumaila	2.1	--	480,000

Table A-5 (Continued). SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U.S.

AFRICA

Country and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Nigeria			
Afam	0.09	0.027	8,400
Apara	0.11	0.050	1,000
Bomu	0.20	0.084	46,000
Delta	0.18	0.096	69,800
Ebubu	0.20	0.113	2,600
Imo River	0.20	0.121	104,100
Meji	0.15	0.041	19,400
Meren	0.09	0.048	82,700
Obagi	0.21	0.060	43,100
Oloibiri	0.26	0.179	4,200
Umuechem	0.14	0.076	32,800
Libya			
Amal	0.14	0.093	162,400
Beda	0.45	0.203	7,900
Bel Hedan	0.24	0.120	6,600
Brega*	0.22	--	
Dahra	0.41	0.106	33,300
Defa	0.28	0.140	165,800
El Dib	1.04	0.127	2,200
Es Sider*	0.42	0.160	
Farrud	0.39	0.070	4,500
Gialo	0.56	0.121	359,400
Hofra	0.32	0.082	5,200
Kotla	0.84	0.274	11,900
Nafoora	0.55	0.091	238,800
Ora	0.23	0.119	11,300
Rakb	0.23	0.118	11,500
Samah	0.25	0.127	57,000
Sarir	0.16	0.079	440,000
Umm Farud	0.13	0.033	4,200
Waha	0.24	0.134	129,300
Zaggut	0.30	0.188	2,700
Zelten	0.23	0.090	357,900

* Export crude mixture delivered to pipeline terminals.

Table A-5 (Continued). SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U.S.

AFRICA (Cont'd)

Country and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Egypt			
Asl	2.05	--	*
El Alamein	0.84	0.075	2[illegible],600
El Morgan	1.67	0.183	260,900
Sudr	2.06	--	*
Angola (Cabinda)			
Tobias	1.51	--	--
Algeria			
Edjeleh	0.095	0.058	18,900
Gassi Touil	0.020	0.008	59,000
Hassi Messaoud	0.15	0.018	387,200
Ohanet	0.06	--	8,600
Rhourde el Baguel	0.31	0.087	65,900
Tin Fouye	0.13	0.061	46,200
Zarzaitine	0.06	0.018	44,200

Table A-5 (Continued). SULFUR AND NITROGEN CONTENT OF CRUDE OILS FROM NATIONS WHICH EXPORT TO THE U.S.

ASIA

Country and Field	Sulfur, Weight Percent	Nitrogen, Weight Percent	Production, bbl/day
Indonesia			
Bekasap	0.17	0.124	111,100
Duri	0.18	0.337	37,900
Kalimantan	0.07	--	--
Lirik	0.08	--	4,500
Minas	0.115	0.132	408,700
Pematang	0.10	0.159	67,300
Seria	<.10	--	--
Tarakan	0.13	--	1,600*

Source: Magee, E. M., H. J. Hall, and G. M. Varga, Jr., Potential Pollutants in Fossil Fuels, PB 225 039, EPA-R2-73-249, Contract No. 68-02-0629, Linden, N.J., Esso Research and Engineering Co., 1973.

APPENDIX B

PROPERTIES AND CHARACTERISTICS OF PETROLEUM PRODUCTS

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Table B-1. GASOLINE REQUIREMENTS

Gasoline	Minimum percentages to be evaporated at temperatures, °F shown below					Distillation residue, max, %	Vapor pressure, max, lb[h]			Research method octane number,[b] min	Copper strip corrosion, max	Gum, max, mg per 100 ml	Sulfur
	10 per cent			50 %	90 %								
	W[a]	*F*[a]	*S*[a]				*W*[a]	*F*[a]	*S*[a]				
Type A	140	149	158	284	392	2	15.0[g]	11.5	10[i]	87 or 96[c]	No. 1	5[e]	[f]
Type B	140	149	158	257	356	2	15.0[g]	11.5	10[i]	87 or 96[c]	No. 1	5[e]	[f]
Type C	167	167	167	284	392	2	15.0[g]	11.5	10[i]	[d]	No. 1	5[e]	[f]

[a] *W*, *F*, and *S* denote the seasonal variations indicated in Table B-2.

[b] In all cases the octane number shall be agreed upon between the purchaser and the seller.

[c] The numerical values shown are minimum values currently encountered in service stations. The lower value pertains to regular-price gasolines, and the higher value to premium-price gasolines. For more detailed information on current levels for both Research and Motor octane numbers, as well as for other characteristics of motor gasoline, reference is made to the series of semiannual reports, issued as Information Circulars (I.C.) by the U.S. Bureau of Mines and entitled *National Motor Gasoline Survey*.

[d] The information available does not permit designation of a minimum Research octane number value for Type C gasoline.

[e] In the case of gasoline containing added nonvolatile material, the gum requirement shall apply to the base stock.

[f] The technical data available do not afford an adequate basis for specifying maximum sulfur content. At the time of this report, gasolines containing up to 0.25 per cent sulfur (ASTM Methods D 90 and D 1266) were distributed within the United States.

[g] The maximum vapor pressure shall be 13.5 lb in Section 3 and in March and November in Section 2, (see Table B-2).

[h] Lower maximum vapor pressures may be required for operations at high altitudes or where abnormally high fuel system temperatures are encountered as in some heavy-duty equipment [(see Section 1 (b))] and in some heavy-duty operations.

[i] These values shall be 9.5 lb, max, in Arizona, California, Colorado, Nevada, New Mexico, and Utah.

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Table B-2. SCHEDULE FOR GEOGRAPHICAL SEASONAL VARIATIONS IN GASOLINE REQUIREMENTS

Territory	Month											
	January	February	March	April	May	June	July	August	September	October	November	December
Section 1	W	W	W or F	F	F or S	S	S	S	S or F	F	F or W	W
Section 2	W	W or F	W or F	F or S	F or S	S	S	S	S or F	F	F or W	F or W
Section 3	W	W or F	F or S	F or S	S	S	S	S	S	S or F	F	F or W
Section 4	F	F or S	F or S	S	S	S	S	S	S	S or F	S or F	F

Section 1

Idaho
Iowa
Maine
Michigan
Minnesota
Montana
New Hampshire
North Dakota
South Dakota
Vermont
Wisconsin
Wyoming

Section 2

Colorado
Connecticut
Delaware
District of Columbia
Illinois
Indiana
Kansas
Kentucky
Maryland
Massachusetts
Missouri

Nebraska
Nevada
New Jersey
New York
Ohio
Oregon
Pennsylvania
Rhode Island
Utah
Virginia
Washington
West Virginia

Section 3

Alabama
Arizona[a]
Arkansas
California
Georgia
Mississippi
New Mexico[a]
North Carolina
Oklahoma
South Carolina
Tennessee
Texas[a]

Section 4

Arizona[b]
Florida
Louisiana
New Mexico
Texas[b]

[a] North of 33 deg latitude.
[b] South of 33 deg latitude.

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Table B-3. AVERAGE PROPERTIES OF JET FUELS SOLD IN U.S.

Property	Average values		
	Type A	Type B	Type A-1
Gravity, °API	43.9	52.0	43.3
Distillation temperatures, °F:			
Initial boiling point	338	137	333
10% point	369	222	360
20% point	382	254	372
50% point	410	315	401
90% point	464	423	464
Final boiling point	500	480	501
Evaporation, % at 400°F	37.9	82.6	48.4
Freezing point, °F	−54	−76	−64
Viscosity, kinematic, at −30°F	8.85	2.94	8.04
Water tolerance, ml	0.2	0.1	0.2
Aniline point, °F	145.8	132.9	139.1
Aniline-gravity constant	6.401	6.911	6.058
Sulfur, wt %:			
Total	0.055	0.044	0.071
Mercaptan	0.0002	0.0006	0.0004
Aromatic content, vol %	14.1	12.3	15.3
Olefin content, vol %	1.2	0.9	1.0
Smoke point, mm	24.3	26.4	23.2
Gum, mg/100 ml, steam jet at 450°F:			
Existent	0.8	0.7	0.7
16-hr accelerated	1.8	1.3	1.6
Net heat of combustion, Btu/lb	18,600	18,703	18,571

Source: Blade, O. C., Survey of Aviation Fuels, Petroleum Research Center, Bureau of Mines, Bartlesville, Okla., 1963.

Table B-4. APPRO 'MATE PROPERTIES OF 20 REPRESENTATIVE NAPHTHAS

Property	Key number of solvent																			
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
API gravity	75.1	75.5	74.6	**53**-70.5	71.5	**40**	64	**62**	**59.5**	**37-58**	**46**	58	**40**	**35**	**35-50**	50	48	**30-50**	45	40
I.B.P., °F	95	115	125	160	105	179	195	**205**	**200**	200	225	220	240	275	303	312	325	357	350	320
10 per cent	115		136	....	....	...	....	....	210	215	...	230	...	280	317	322	333	367	375	375
50 per cent	135	150	162	175	180	191	200	**210**	217	232	242	250	285	300	328	337	350	380	400	485
90 per cent	156		188	195	220	245	210	**220**	**232**	253	...	270	...	330	352	368	370	397	430	
E.P., °F	180	160	206	210	260	275	215	**240**	**247**	286	**280**	300	340	360	376	380	400	410	455	550
Flash (Tag C.C.), °F	-73	....	-40	....	....	...	....	....	25	25	...	45	..	89	99	..	115	136	142	145
Kauri butanol No.	...	30.5	34.5	33.5-**49**	34	**77**	35.5	37.5	**38.5**	**39-69**	**54**	38	**72**	**73**	**35-63**	33	35	**31-65**	32	

• Solvents high in aromatic hydrocarbons (high solvency) are shown boldface.

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Table B-5. USES OF 20 REPRESENTATIVE NAPHTHAS

Use of solvent	Boiling range, °F	Key number of solvent with boiling ranges, °F																			
		1 95–186	2 145–160	3 125–206	4 160–210	5 105–260	6 179–275	7 195–215	8 205–240	9 200–247	10 200–285	11 225–280	12 220–300	13 240–340	14 275–360	15 300–370	16 312–380	17 325–400	18 357–410	19 350–455	20 320–650
1. Perfume extraction	160–260	...	...	...	x	x															
2. **Carter oil or fat extraction**	125–300	...	...	x	x	x	...	x	...	x	x	...	x	...							
3. **Toluene** substitute, **lacquer formulas, fast-setting varnishes**	179–275	...	...	...	...	...	x														
4. **Seed extraction**	160–300	...	...	...	x	x	...	...	...	x	x	...	x								
5. **Rubber cements, tire manufacture**	95–370	x	x	x	x	x	...	x	...	x	x	x	x	...	...	x					
6. **Lacquers, art leather, rotogravure ink,** adhesive tape	95–370	x	x	x	x	x	...	x	...	x	x	...	x	...	...	x					
7. **Rosin extraction, shade cloth, rubber dip goods**	205–300	...	...	...	...	...	...	...	x	x	x	...	x								
8. **Brake linings, leather degreasing, bone degreasing**	125–400	...	...	x	x	x	...	x	...	x	x	x	x	...	...	x	...	x			
9. **Printer's ink, cellulose lacquer diluent**	160–370	...	...	...	x	...	...	...	...	...	...	x	...	...	...	x					
10. Paints and varnishes, thinners	105–455	...	...	...	...	x	...	...	...	x	x	...	x	...	x	x	...	x	x	x	
11. Textile printing and proofing	160–410	...	...	...	x	...	...	x	...	x	x	...	x	...	...	x	...	x	x		
12. Paints and coatings (aircraft), **paint removers and solvents**	179–410	...	...	...	...	...	x	...	...	...	x	...	...	x	x	...	...	...	x		
13. Paint shop rinsing and cleaning (aircraft)	240–340	...	...	...	...	...	...	...	...	...	...	...	...	x							
14. **Floor coverings, wax, polish, wash for printing plates or rolls**	200–410	...	...	...	...	...	...	...	...	x	...	...	x	...	...	x	...	x	x		
15. **Dry cleaning, metal and machinery cleaning**	200–400	...	...	...	...	...	...	...	...	x	x	...	x	...	...	x	x	x			
16. **Zylol substitute (in many instances)**	275–370	...	...	...	...	...	...	...	...	...	...	...	...	...	x	x					
17. Flat finishes, rustproof compounds	300–455	...	...	...	...	...	...	...	...	...	...	...	...	...	...	x	x	x	x	x	
18. **Synthetic resin thinner**	357–410	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	x		
19. **Wood preservatives**	312–650	...	...	...	...	...	...	...	...	...	...	...	...	...	...	x	...	...	...	...	x

* **Solvents high in aromatic hydrocarbons (high solvency) are shown boldface.**

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Table B-6. AVERAGE OF SELECTED PROPERTIES OF CENTRAL REGION DIESEL FUELS

Property	Class 1, Type C-B	Class 2, Type T-T	Class 3, Type R-R	Class 4, Type S-M
Gravity, °API	41.9	37.3	34.8	34.0
Viscosity at 100°F:				
Kinematic, cs	1.84	2.54	2.74	2.79
Saybolt Universal, sec	32.1	34.6	35.2	35.4
Sulfur content, wt %	0.142	0.223	0.287	0.543
Aniline point, °F	148.6	146.2	140.2	139.3
Ramsbottom carbon residue on 10% residuum, %	0.057	0.088	0.117	0.163
Ash, %	0.0005	0.0009	0.0010	0.0023
Cetane number	51.1	50.0	47.0	46.7
Distillation test:				
IBP, °F	356	380	388	397
10%, °F	393	430	440	448
50%, °F	440	490	502	509
90%	501	557	574	582
EP, °F	542	600	618	622

* Central region: Minnesota, Iowa, Wisconsin, Illinois, Indiana, Missouri, Kansas; parts of Oklahoma, Michigan, Kentucky, Arkansas, Texas, Nebraska, and the Dakotas.

Source: Blade, O. C., Diesel Fuel Oils, Bureau of Mines Petroleum Experiment Station, Bartlesville, Okla., 1966.

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Table B-7. CHARACTERISTICS OF THREE GRADES OF UNITED STATES FUEL OIL

Property	Grade 1	Grade 2	Grade 4
Gravity, °API	42.6	34.9	21.2
Viscosity at 100°F, cs	1.79	2.61	15.41
Sulfur, wt %	0.071	0.249	0.77
Ramsbottom carbon residue, wt %	0.052	0.116	3.30
Distillation, °F:			
Initial boiling point	349	370	422
10% point	390	432	496
50% point	437	499	674
Final boiling point	533	629	754

Source: Blade, O. C., Burner Fuel Oils, Bureau of Mines, Bartlesville, Okla., 1960.

Table B-8. CHARACTERISTICS OF RESIDUAL HEATING OILS

Property	Grade 5	Grade 6
Gravity, °API	17.1	12.3
Viscosity:		
Kinematic at 100°F, cs	60.2	
Furol at 122°F, sec	25.8	170.2
Sulfur content, %	1.07	1.33
Ramsbottom carbon residue on 100% sample, %	6.7	10.7
Ash, %	0.035	0.41
Water and sediment, vol %	0.16	0.15

Source: Blade, O. C., Burner Fuel Oils, Bureau of Mines, Bartlesville, Okla., 1962.

Table B-9. PROPERTIES OF KEROSENE, TRACTOR FUEL, AND RELATED PRODUCTS

Name of product	Gravity, API	Flash, °F min	Dist. temp, °F			Sulfur %, max	Smoke point, min	Corrosion, copper-strip	Color, Saybolt, min	Burning test, time	Others
			I.B.P., in	10% recovered, max	E.P., max						
Kerosene:											
Special arctic export	46–49	110–120	300–325		465–490	0.05–0.1			+30	24 hr	
Signal or long-time burning oil	44–48	110–125	300–335		480–600	0.04–0.1	29–34		+25 to +30	120 min (and 14 day)	10 wick char
Domestic, 41–43, w.w.	41–44	105–130	350–370		480–572	0.05–0.1	25–30		+16 to +30	24 hr	20 wick char
Domestic, 44–46, w.w.	44–46	110–130	350–370		470–572	0.03–0.1	26–32		+30	24 hr (and 21 day)	
Federal, VV-K-211a		115			572	0.13			+16	24 hr	
300°F mineral-seal	36–39	250–260	480–540		600–700				+16 to +25	20 hr	
Range oil	43	145			515				+25	72 hr	
Tractor fuel, ASTM D1215:											
Light grade				347	465–518[a]	1.0		Pass			35 min o.n.
Regular grade				347–401	465–518[a]	1.0		Pass			35 min o.n.
Distillate, ASTM D396:											
1955 Grade No. 1	35.2–48.5	114–185	317–396	350–420	487–586	0.018–0.5[b]		Pass			−10 to −60 pour point
1956 Grade No. 2	34.8–44.9	120–185	312–382	360–428	474–620	0.01–0.96[b]		Pass			Zero to −65 pour point
Rocket fuel, RP-1	42–45	110		365–410	525	0.05	28	Pass			Freezing point −40°F Aromatics, 5% max

[a] Temperatures at 95% recovered.
[b] Special services require 0.5 max.

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Table B-10. RANGE OF PHYSICAL PROPERTIES OF LUBRICATING OILS

Name of oil	Used for	API	Viscosity at			Viscosity index	Flash (open cup)	Pour point	Carbon residue	Compounding, per cent	Special property
			100°F	130°F	210°F						
Motor, light	Automotive engine	24-30	......	90-165	40-55	70-100	360-400	−10 to 15	0.03-0.5	......	Detergency and Viscosity Index
Motor, medium	Automotive engine	22-28	400-650	165-293	62-90	50-100	400-450	0 to 25	0.1-0.9		Detergency and Viscosity Index
Motor, heavy	Automotive engine	20-27	......	......	90-155	40-100	440-510	0 to 25	0.2-1.5		Detergency and Viscosity Index
Aircraft engine, light	Airplanes	24-26	......	......	60-85	90-100	400-435	−10 to 0	0.5-1.0		Settle from salt solution, 60 min
Aircraft engine, heavy	Airplanes	23-25	......	......	100-145	90-100	475-500	0 to 30	1.5-2.0	......	Settle from salt solution, 60 min
Diesel engine, lightest	Diesels	23-25		120-185	...	40-70	330-390	−10 to 10	0.2-0.5		
Diesel engine, heaviest	Diesels	22-25	......	......	75-90	40-70	390-410	0 to 20	0.3-0.8	......	
Transmission oil, lightest	Automobiles	21-23	800-1,000	......	......	......	300-420	−10 to 10	......	......	Precipitation number, 0.1 max
Transmission oil, heaviest	Automobiles	20-22	......	......	200	......	300+	0 to 30	......	......	Precipitation number, 0.1 max
Engine and machine, spindle	Textiles, etc.	25-27	100-125	......	......	......	320-350	0 to 30	......	......	Viscosity
Engine and machine, heaviest	Heavy machinery	21-26	700-800	......	......	......	375-400	0 to 30	......	......	Viscosity
Cold test, light	Refrigeration, etc.	27-32	140-170	......	......	......	310-350	−30 max	......	......	Low pour point
Cold test, heavy	Refrigeration, etc.	25-28	300-325	......	......	......	340-400	−10 max	......	......	Low pour point
Cylinder oils, unfiltered:											
Light mineral	Engine or compressor cylinders	25-28	......	......	135-165	......	490-540	20 to 60	2.0-3.0	None	Neutralization number, 0.15 max
Heavy mineral		20-26	......	......	175-220	......	520-600	30 to 50	3.0-4.0	None	Neutralization number, 0.15 max
Light compounded		25-28	......	......	95-110	......	450-510	10 to 40	1.0-2.0	6-10	Neutralization number, 1.0 max
Heavy compounded		20-26	......	......	175-220	......	520-600	30 to 60	3.0-4.0	5-7	Neutralization number, 1.0 max
Marine engine, mineral	Marine engines	23-28		......	65-75	......	330-410	35 max		None	Neutralization number, 0.1 max
Marine engine, compound	Marine engines	23-28	......	......	65-80	......	350-410	35 max	...	15-20	Neutralization number, 3.0 max
Turbine oil, light	Steam turbines, dynamos, high speed, etc.	29-31	120-175	......	......	......	310-360	0 to 35	0.02-0.1		Steam emulsion number, demulsibility, and high oxidation number also specified
Turbine oil, medium		27-30	175-340	......	......	......	320-410	0 to 35	0.06-0.3		
Turbine oil, heaviest		26-28	475-525	......	......	......	330-430	35 max	0.1-0.4		
Transformer oil	Electrical transformers	26-30	55-65	......	......	......	275-325	−50 to −30	......	......	Dielectric strength, 1-in. disk, 0.1-in. gap, 25,000 volts
Black oil, summer	Rough slow-speed bearings, crushers, etc.	20-25	400-500	......	......	......	......	0 to 30	......	......	Insoluble per cent, 0.1
Black oil, winter		20-27	200-300	......	......	......	......	−20 to 0	......	......	Insoluble per cent, 0.1
White oil	Food manufacturing, textiles, paper, etc.	30-32	55-140	......	......	......	290-390	......	......	......	Colorless

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Table B-11. CHARACTERISTICS OF GREASES

Soap base	Calcium (general)	Calcium resinoid (cold-set)	Sodium (general)	Sodium, brick type	Aluminum	Lithium	Mixed sodium calcium
Texture	Buttery	Buttery	Fibrous or smooth	Hard or brittle	Buttery, rubbery, or stringy but never fibrous	Buttery or stringy	Buttery to fibrous
Dropping point, °F (approx.)	220–225	275	300–450	300–450	200	400	315
Condition after having heated to melting point	Separates	Foams at 200°F. Separates upon prolonged heating	No change if worked	No change	Changes texture upon cooling but does not separate even above melting point	No change if worked	No change if worked
Maximum temperature, °F (continuous service)	175	200	300–400	300–450	150 or perhaps 200	300	300
Softening upon working	Fair to poor	Fair to poor	Varies—excellent to poor	Varies—fair to poor	Fair to poor	Varies—excellent to poor	Varies—excellent to poor
Effect of water	Resistant	Resistant	Susceptible	Susceptible	Resistant	Resistant	Susceptible
Primary use	General-purpose lubricant for plain bearings and line shafting. Pressure gun and water pumps	Rough heavy bearings at slow speeds, also skids, track curves, and wagon wheels. Oil field and agricultural machinery	Ball and roller bearings up to medium speeds and light to heavy loads, also wheel bearings and chassis	Locomotive driving journals and similar services	Applications requiring adhesiveness or resistance to centrifugal force	Aircraft or services down to −100°F	All types ball and roller bearings and special applications at both high and low temperatures
Notes	Some moisture left in grease. Certain greases stabilized with chemicals instead of water can be used at higher temperatures	Cheapness is major factor	Normally does not channel. Highest temperature service except strontium greases	Difficulty is susceptibility to water. Smooth greases used for antifriction bearings. Long-fiber greases for chassis lubrication	Does not oxidize or crust readily. Good slow flow properties. Relatively expensive	Offers possibilities for general purposes	Special types are resistant to oxidation or crusting and can be used for electric motors or seldom lubricated equipment

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Table B-12. COMPARISON OF WAX TYPES PRODUCED IN THE UNITED STATES

Wax	Characteristic	No. of carbon atoms	Melting point, °F	Viscosity at 210°F, SSU	Crystals
Paraffin	Brittle	18–56	122–140	40	Plates
Motor oil	Brittle	26–42	145–170	50	Needles
Residual	Flexible	36–70	145–175	65–100	Small needles
Tank bottom	Hard	40–70	180–200	......	Very small needles

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Table B-13. SPECIFICATIONS FOR ASPHALT CEMENT OF THE ASPHALT INSTITUTE

Characteristics	AASHO* Test Method	ASTM Test Method	Grades				
			Industrial and special	Paving			
Penetration, 77°F, 100 g., 5 sec	T 49	D 5	40-50	60-70	85-100	120-150	200-300
Viscosity at 275°F:							
Saybolt Furol, SSF	......	E 102	120 +	100 +	85 +	70 +	50 +
Kinematic, cs	....	D 445	240 +	200 +	170 +	140 +	100 +
Flash point (Cleveland open cup), °F	T 48	D 92	450 +	450 +	450 +	425 +	350 +
Thin-film oven test	T 179	......	......	......	......	......	......
Penetration after test, 77°F, 100 g., 5 sec, % of original	T 49	D 5	52 +	50 +	45 +	42 +	37 +
Ductility:							
At 77°F, cms	T 51	D113	100 +	100 +	100 +	60 +	......
At 60°F, cms	......	......	......	......	......	......	60 +
Solubility in carbon tetrachloride, %	T 44†	D 4†	99.5 +	99.5 +	99.5 +	99.5 +	99.5 +
General requirements	......	......	The asphalt shall be prepared by the refining of petroleum. It shall be uniform in character and shall not foam when heated to 350°F				

* American Association of State Highway Officials.

† Except that carbon tetrachloride is used instead of carbon disulfide as solvent, Method No. 1 in AASHO Method T 44 or Procedure No. 1 in ASTM Method D 4.

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Table B-14. PROPERTIES OF PETROLEUM COKES

	Early pet. cokes, 1930–1935		Oven cokes	Delayed process cokes	Continuous or fluid cokes
	Cracking still	Coking still			
Moisture, wt %	0.15–3.3	0.3–1.8	0.3–2	Nil–0.5	
Volatile combustible matter, wt %	8–18	2–13	0.6–7.4	8–18	3.7–5.3
Ash, wt.	0–1.6	0.5–1.2	0.2–1.8	0.5–1.6	0.1–2.8
Sulfur, wt %	0.2–4.2	0.5–1.2	0.8–1.5	0.5–4.2	1.1–7.0
Bulk density, lb per cu ft	56–69		....	....	55–65
True or real density, g per ml	....	....	....	1.28–1.42	1.5–1.6
Btu per lb as rec'd	15,300–16,400	14,500–15,500	14,400–14,700	....	14,000
Hydrogen, wt %	....	....	....	....	1.6–2.1
Carbon, wt %	....	....	....	....	88.3–92.5

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Table C-1. COMPLETE LIST OF UNITED STATES REFINERIES BY COMPANIES

	COMPANY	LOCATION	REFINERY[1] CAPACITY (m^3/day)	PRODUCTION CAPACITY LUBES[1] (m^3/day)	ASPHALT[1] (m^3/day)	COKE[1] (metric tpd)	OPERATING[2] GASOLINE OUTPUT (m^3/day)
1.	**Adobe Refining Co.**	LaBlanca, Tex.	676	---	---	---	---
2.	**Allied Materials Corp**	Stroud, Okla.	875	143	192	---	---
3.	**Amerada-Hess**	Fort Reading, N.J.	11100	---	---	---	5090
4.		Purvis, Miss.	4530	---	---	291	2850
5.	**American Petrofina**	Eldorado, Kan.	3980	---	318	---	1690
6.		Mt. Pleasant, Tex.	4130	---	1270	---	1510
7.		Port Arthur, Tex.	13400	---	---	---	4170
8.	Amoco Oil	Savannah, Ga.	1910	---	1270	---	---
9.		Wood River, Ill.	17000	---	1720	---	5470
10.		Whiting, Ind.	50100	1380	4930	663	20000
11.		Baltimore, Md.	1590	---	1270	---	---
12.		Sugar Creek, Mo.	16700	---	1030	409	5950
13.		Mandan, N. Dakota	7630	---	---	---	3180
14.		Texas City, Tex.	52900	---	843	726	39400
15.		Salt Lake City, Utah	6200	---	398	---	2770
16.		Yorktown, Va.	8430	---	---	645	3820
17.		Casper, Wyoming	6840	204	246	---	1570
18.	APCO Oil Corp.	Arkansas City, Kan.	3980	---	223	---	2540
19.		Cyril, Okla.	1910	---	207	---	763
20.	Arizona Fuels Corp.	Fredonia, Ariz.	1590	---	---	---	---
21.		Roosevelt, Utah	1750	---	---	---	---
22.	Ashland Petroleum	Calettsburg, Ky.	21000	---	1590	---	8080
23.		Louisville, Ky.	3980	---	557	---	1370
24.		Tonawanda, N.Y.	10300	---	1590	---	3500
25.		Canton, Ohio	9540	---	1590	---	4370
26.		Findlay, Ohio (Seasonally)	1590	---	954	---	---
27.	Atlantic Richfield Co.	North Slope, Alaska	763	---	---	---	---
28.		Carson, Calif.	26200	---	---	1630	13700
29		East Chicago, Ind.	20000	---	1650	---	7600
30.		Philadephia, Penn.	29400	---	3100	---	12600
31.		Houston, Tex.	33900	1030	---	1180	20100
32.		Ferndale, Wash.	15300	---	---	1360	9740
33.	Atlas Processing	Shreveport, La.	4510	---	---	---	1270
34.	Bay Refining - Dow Chem.	Bay City, Mich.	2700	---	---	---	525
35.	Bayou State Oil Corp.	Hosston, La.	557	200	80	---	---
36.	Beacon Oil Co.	Hanford, Ca.	1910	---	---	---	411
37.	Berry Petroleum Co.	Stephens, Ark.	477	---	160	---	---
38.	Big West Oil Co.	Kevin, Mon.	915	---	52	---	216
39.	B. P. Oil Corp.	Marcus Hook, Penn.	15600	---	---	---	7710
40.	Bradford Petroleum	Bradford, Penn.	1110	493	---	---	286
41.	British Petroleum Co.	North Slope, Alaska	200	---	---	---	---
42.	**Calumet Refining Co.**	Princeton, La.	382	270	76	---	---
43.	**Canal Refining Co.**	Church Point, La.	398	---	---	---	200
44.	Caribou Four Corners, Inc.	Kirtland, N. Mex.	350	---	---	---	---
45.		Woods Cross, Utah	668	---	---	---	477

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Table C-1 (Continued). COMPLETE LIST OF UNITED STATES REFINERIES BY COMPANIES

	COMPANY	LOCATION	REFINERY(1) CAPACITY (m^3/day)	PRODUCTION CAPACITY			
				LUBES(1) (m^3/day)	ASPHALT(1) (m^3/day)	COKE(1) (metric tpd)	OPERATING(2) GASOLINE OUTPUT (m^3/day)
46.	Cenex	Laurel, Mon.	6680	---	---	---	3070
47.	Champlin Petroleum Co.	Corpus Christi, Tex.	9860	---	---	---	5100
48.		Wilmington, Calif.	4610	---	---	522	398
49.		Enid, Okla.	7870	175	223	150	5380
50.	Charter International Oil Co.	Houston, Texas	11100	---	636	---	4450
51.	Chevron Asphalt Co.	Baltimore Md.	2150	---	1750	---	---
52.	Chevron Oil Co.	Perth Amboy, N.J.	14000	---	3980	---	3420
53.		El Paso, Tex.	11300	---	795	---	5450
54.		Salt Lake City, Utah	7160	---	---	---	2850
55.	Cities Service Oil Co.	Lake Charles, La.	42600	1110	---	908	17300
56.	Clark Oil & Refining Corp.	Blue Island, Ill.	10800	---	716	---	7600
57.		Hartford, Ill.	5720	---	---	409	6480
58.	Coastal States Petrochemical Co	Corpus Christi, Tex.	21500	---	80	454	7080
59.	Continental Oil Co.	Billings, Mon.	8350	---	557	---	3380
60.		Commerce City, Colo.	4770	---	525	---	1700
61.		Ponca City, Okla.	18600	366	477	454	9410
62.		Westlake, La.	13200	---	---	454	5600
63.		Wrenshall, Minn.	3740	---	---	---	1060
64.	Cosden Oil & Chemical Co.	Big Spring, Tex.	10300	---	1270	---	8740
65.	Cotton Valley Solvents Co.	Cotton Valley, La.	1230	---	---	---	---
66.	CRA Inc.	Coffeyville, Kan.	5570	239	---	272	2860
67.		Phillipsburg, Kan.	3180	---	318	---	1510
68.		Scottsbluff, Neb.	795	---	---	---	350
69.	Cross Oil & Refining Co.	Smackover, Ark.	771	207	223	---	---
70.	Crown Central Petroleum Corp.	Houston, Texas	15900	---	---	272	8045
71.	Crystal Refining Co.	Carson City, Mich.	986	---	---	---	---
72.	Delta Refining Co.	Memphis, Tenn.	4610	---	477	---	2230
73.	Derby Refining Co.	Wichita, Kan.	4110	---	---	145	2020
74.	Diamond Shamrock Oil & Gas Co.	Sunray, Texas	7470	---	398	---	4130
75.	Douglas Oil Co. of Calif.	Paramount, Calif.	5570	---	2230	---	986
76.		Santa Monica, Calif.	1300	---	922	---	---
77.	Eddy Refining Co.	Houston, Texas	517	---	---	---	---
78.	Edgington Oil Co.	Long Beach, Calif.	4610	---	1190	---	---
79.	Edgington Oxnard Refinery	Oxnard, Calif.	398	---	---	---	---
80.	Evangeline Refining Co., Inc.	Jenings, La.	684	---	---	---	95
81.	Exxon Oil Co.	Benica, Calif.	13800	---	---	817	12000
82.		Baytown, Tex.	63600	3980	1910	---	26500
83.		Baton Rouge, La.	70800	2390	4600	1960	33000
84.		Billings, Mon.	7160	---	2070	227	3700
85.		Lindon, N.J.	43700	---	7310	---	18400
86.	Famariss Oil Corp.	Monument, N. Mex.	795	---	---	---	95
87.	Fletcher Oil & Refining Co.	Carson, Calif.	2510	---	---	---	557
88.	Flint Chem. Co.	San Antonio, Tex.	191	---	---	---	---
89.	Gary Western Co.	Grand Junction, Colo.	1320	---	---	363	---
90.	Getty Oil Co., Inc.	Delaware City, Del.	22300	---	---	1630	11700

Table C-1 (Continued). COMPLETE LIST OF UNITED STATES REFINERIES BY COMPANIES

	COMPANY	LOCATION	REFINERY$^{(1)}$ CAPACITY (m^3/day)	PRODUCTION CAPACITY LUBES$^{(1)}$ (m^3/day)	PRODUCTION CAPACITY ASPHALT$^{(1)}$ (m^3/day)	PRODUCTION CAPACITY COKE$^{(1)}$ (metric tpd)	PRODUCTION CAPACITY OPERATING$^{(2)}$ GASOLINE OUTPUT (m^3/day)
91.	Gladieux Refinery	Fort Wayne, Inc.	1590	---	---	---	40
92.	Golden Bear, Div.	Oildale, Calif.	1670	636	509	---	---
93.	Golden Eagle Refining	Carson, Calif.	2070	---	---	---	---
94.	Good Hope Refineries	Good Hope, La.	4680	---	---	---	557
95.	Gulf Oil Co.	Sante Fe Springs, Calif.	8190	---	636	---	4530
96.		Belle Chasse, La.	28700	---	---	763	16900
97.		Venice, La.	4560	---	---	---	3550
98.		Cleves, Ohio	6690	---	461	---	3820
99.		Toledo, Ohio	8000	---	318	---	3790
100.		Philadelphia, Penn.	26800	---	---	---	15300
101.		Port Arthur, Tex.	49600	2010	---	1260	26500
102.	Hawaiian Indep. Ref.	Barber's Point, Hawaii	4770	---	---	---	---
103.	Howell Hydrocarbons	San Antonio, Texas	493	---	---	---	159
104.	Hunt Oil	Tuscaloosa, Ala.	2390	---	827	---	191
105.	Husky Oil	North Salt Lake, Utah	1830	---	---	---	652
106.		Cheyenne, Wy.	3750	---	477	---	2040
107.		Cody, Wy.	1700	---	636	---	763
108.	Ind. Farm Bur. Coop.	Mt. Vernon, Ind.	2390	---	---	---	986
109.	Jet Fuel Refinery	Mosby, Mon.	159	---	---	---	---
110.	Kern County Refining Co.	Bakersfield, Calif.	2050	---	---	---	509
111.	Kerr McGee Corp.	Cotton Valley, La.	1190	---	---	---	553
112.		Wynnewood, Okla.	5090	---	557	---	3930
113.	Koch Refining Co.	Pine Bend, Minn.	17000	---	3180	1180	6730
114.	LaGloria Oil & Gas Co.	Tyler, Texas	4450	---	---	73	2730
115.	LaJet Inc.	St. James, La.	1750	---	---	---	---
116.	Lakeside Refining Co.	Kalamazoo, Mich.	954	---	---	---	191
117.	Laketon Asphalt Refining, Inc.	Laketon, Ind.	1350	---	413	---	---
118.	Lion Oil Co.	El Dorado, Ark.	7000	127	954	---	2660
119.	Little America Refining Co.	Casper, Wy.	3500	---	318	---	1700
120.	Longview Refining Co.	Longview, Tex.	1050	---	---	---	239
121.	Lunday-Thagard Oil Co.	South Gate, Calif.	795	---	254	---	---
122.	MacMillan Ring - Free Oil Co, Inc.	Norphlet, Ark.	716	---	199	---	---
123.		Signal Hill, Calif.	1510	---	---	---	---
124.	Marathon Oil Co.	Robinson, Ill.	31000	---	---	817	11100
125.		Detroit, Mich.	9220	---	1380	---	4640
126.		Texas City, Texas	9700	---	---	---	3130
127.	Marion Corp.	Mobile, Ala.	2390	---	---	---	---
128.	Mid America Refinery Co., Inc.	Chanute, Kan.	493	---	---	---	---
129.	Midland Cooperatives, Inc.	Cushing, Okla.	3020	---	---	73	1540
130.	Mobil Oil Corp.	Ferndale, Wash.	11400	---	---	---	4320
131.		Beaumont, Texas	51700	1400	16	1090	25600
132.		Buffalo, N.Y.	6770	---	1190	---	3200
133.		Paulsboro, N.J.	15600	1020	---	885	5660
134.		Augusta, Kan.	7950	---	1270	---	3690
135.		Torrance, Calif.	19600	---	---	2540	14100

Table C-1 (Continued). COMPLETE LIST OF UNITED STATES REFINERIES BY COMPANIES

	COMPANY	LOCATION	REFINERY$^{(1)}$ CAPACITY (m^3/day)	PRODUCTION CAPACITY			
				LUBES$^{(1)}$ (m^3/day)	ASPHALT$^{(1)}$ (m^3/day)	COKE$^{(1)}$ (metric tpd)	OPERATING$^{(2)}$ GASOLINE OUTPUT (m^3/day)
136.	Mobile Oil Corp., Inc.	Joliet, Ill.	27800	---	---	1540	14500
137.		East Chicago, Ind.	7470	---	---	---	3670
138.	Mohawk Petroleum Corp., Inc.	Bakersfield, Calif.	3510	---	---	---	350
139.	Mountaineer Refining Co., Inc.	LaBarge, Wy.	80	---	---	---	---
140.	Murphy Oil Corp.	Meraux, La.	14700	---	---	---	3690
141.		Superior, Wisc.	5880	---	1910	---	2240
142.	National Cooperative Ref. Assoc	McPherson, Kan.	8610	---	---	318	3350
143.	Navajo Refining Co.	Artesia, N. Mex.	3330	---	223	---	914
144.	Newhall Refining Co., Inc.	Newhall, Calif.	1190	---	477	---	---
145.	North American Petroleum Corp	Shallow Water, Kan.	795	---	---	---	---
146.	Northwestern Refining Co.	St. Paul Park, Minn.	9540	---	3500	---	3330
147.	OKC Refining Inc.	Okmulgee, Okla.	3420	---	223	---	1990
148.	Osceola Refining Co.	West Branch, Mich.	1510	---	---	----	---
149.	Pasco, Inc.	Sinclair, Wy.	6360	---	366	---	2630
150.	Pennzoil Co.	Rouseville, Penn.	1590	561	---	---	448
151.		Falling Rock, W. Va.	795	207	---	---	318
152.	Phillips Petroleum Co.	Borger, Tex.	15100	---	---	---	10600
153.		Kansas City, Kan.	13500	398	477	---	6121
154.		Great Falls, Mon.	906	---	127	---	262
155.		Woods Cross, Utah	3660	---	350	---	1750
156.		Sweeney, Texas	13500	---	---	---	9060
157.		Avon, Calif.	17500	266	---	1090	13500
158.	Plateau, Inc.	Bloomfield, N.Mex.	811	---	---	---	350
159.	Powerline Oil Co.	Santa Fe Springs, Calif.	4530	---	795	---	2130
160.	Pride Refining Inc.	Abilene, Tex.	2240	---	---	---	---
161.	Quaker State Oil Ref. Corp.	Emlenton, Penn.	528	270	---	---	169
162.		Farmers Valley, Penn.	1030	398	---	---	366
163.		Newell, W. Va.	1540	572	---	---	398
164.		St. Mary's, W. Va.	771	270	---	---	183
165.	Quintana-Howell	Corpus Christi, Tex.	1590	---	---	---	---
166.	Rock Island Refining Corp.	Indianapolis, Ind.	4690	---	477	---	2500
167.	Sage Creek Refining	Cowley, Wy.	159	---	---	---	---
168.	San Joaquin Refining	Oildale, Calif.	2700	---	534	---	---
169.	Sequoia Refining Corp.	Hercules, Calif.	4290	---	---	---	2660
170.	Seminole Asphalt Ref.	St. Marks, Fla.	795	---	398	---	---
171.	Shell Oil Co.	Martinez, Calif.	15900	716	1650	---	7880
172.		Wilmington, Calif.	15300	---	---	1630	7360
173.		Wood River, Ill.	41300	890	3580	---	24800
174.		Norco, La.	38200	---	954	817	20200
175.		Ciniza, N.Mex.	3180	---	134	---	1830
176.		Deer Park, Tex.	45800	954	604	---	19100
177.		Odessa, Tex.	5090	---	---	---	2420
178.		Anacortes, Wash.	14500	---	---	---	7710
179.	Skelly Oil Co.	El Dorado, Kan.	11700	---	---	454	6150
180.	Somerset Refinery	Somerset, Ky.	445	---	---	---	---
181.	Sound Refining Inc.	Tacoma, Wash.	716	302	413	---	---
182.	Southland Oil Co.	Crupp, Miss.	668	---	229	---	---

Table C-1 (Continued). COMPLETE LIST OF UNITED STATES REFINERIES BY COMPANIES

	COMPANY	LOCATION	REFINERY[1] CAPACITY (m^3/day)	PRODUCTION CAPACITY LUBES[1] (m^3/day)	ASPHALT[1] (m^3/day)	COKE[1] (metric tpd)	OPERATING[2] GASOLINE OUTPUT (m^3/day)
183.	**Southland Oil Co.**	Lumberton, Miss.	954	---	372	---	---
184.		Sandersville, Miss.	1750	---	554	---	---
185.	**Southwestern Oil & Ref. Co.**	Corpus Christi, Tex.	15900	---	---	---	3720
186.	Southwestern Ref. Co.	LaBarge, Wy.	52	---	---	---	---
187.	Standard Oil of Calif.	Kenai, Alaska	3500	---	48	---	---
188.		Bakersfield, Calif.	4130	---	175	---	1160
189.		El Segundo, Calif.	36600	---	1320	2000	21400
190.		Richmond, Calif.	30200	1590	1750	---	20300
191.		Barber's Point, Hawaii	6360	---	207	---	1860
192.		Portland, Oregon	2230	---	1370	---	---
193.		Richmond Beach, Wash.	716	---	636	---	---
194.	Standard Oil of Ky.	Pascagoula, Miss.	38200	---	---	---	22800
195.	Standard Oil of Ohio	Lima, Ohio	26200	334	---	554	8700
196.		Toledo, Ohio	19100	---	1110	590	8700
197.	Sun Oil Co.	Toledo, Ohio	19900	---	---	---	13800
198.		Duncan, Okla	7710	---	---	363	4390
199.		Tulsa, Okla.	14100	---	668	272	6420
200.		Marcus Hook, Penn.	26200	2700	1910	---	13500
201.	Sunland Ref. Co.	Bakersfield, Calif.	1400	---	---	---	151
202.	Suntide Refining	Corpus Christi, Tex.	9060	---	---	213	4710
203.	Tenneco Oil Co.	Bakersfield, Calif.	191	---	---	---	---
204.		Chalmette, La.	15400	---	---	318	9810
205.	Tesoro-Alaskan Petr.	Kenai, Alaska	6040	---	---	---	---
206.	Tesoro Petroleum	Wolf Point, Mon.	398	---	---	---	---
207.		Carrizo Springs, Tex.	2070	---	---	---	---
208.		Newcastle, Wy.	1670	---	---	---	477
209.	Texaco, Inc.	Wilmington, Calif.	11900	---	---	1500	11800
210.		Lawrenceville, Ill.	13400	---	429	---	7080
211.		Lockport, Ill.	11400	---	---	272	5990
212.		Convent, La.	22300	---	---	---	1230
213.		Westville, N.J.	14000	---	---	---	5250
214.		Anacortes, Wash.	10000	---	---	---	3550
215.		Casper, Wy.	3340	---	239	114	1500
216.		Port Arthur, Tex.	64600	3180	---	---	26200
217.		Amarillo, Tex.	3180	---	---	91	1620
218.		El Paso, Tex.	2700	---	---	91	1510
219.		West Tulsa, Okla.	7950	---	---	---	3580
220.		Port Neches, Tex.	7470	---	1430	---	---
221.	Texas Asphalt & Ref. Co.	Fort Worth, Tex.	477	---	---	---	---
222.	Texas City Refining	Texas City, Tex.	9540	---	---	---	3550
223.	The Refinery Corp.	Commerce City, Colo.	2780	---	---	---	2590
224.	Three Rivers Refinery	Three Rivers, Tex.	238	127	19	---	---
225.	Thriftway Co.	Bloomfield, N. Mex.	338	---	---	---	---
226.	Tonkawa Refining	Tonkawa, Okla.	954	---	---	---	---
227.	Toscopetro Corp.	Bakersfield, Calif.	4220	---	---	191	4300
228.	Total Leonard, Inc.	Alma, Mich.	6500	---	477	---	3530
229.	U.S. Oil & Refining	Tacoma, Wash.	2540	---	477	---	398

Table C-1 (Continued). COMPLETE LIST OF UNITED STATES REFINERIES BY COMPANIES

	COMPANY	LOCATION	REFINERY[(1)] CAPACITY (m^3/day)	PRODUCTION CAPACITY LUBES[(1)] (m^3/day)	PRODUCTION CAPACITY ASPHALT[(1)] (m^3/day)	PRODUCTION CAPACITY COKE[(1)] (metric tpd)	OPERATING[(2)] GASOLINE OUTPUT (m^3/day)
230.	Union Oil Co. of Calif.	Los Angeles, Calif.	17200	---	1590	---	8780
231.		San Francisco, Calif.	17600	572	978	1680	11100
232.		Lemont, Ill.	24200	---	318	908	11300
233.		Nederland, Tex.	18400	557	859	---	8060
234.	Union Texas Petroleum	Winnie, Tex.	1510	---	---	---	1256
235.	United Refining Co.	Warren, Penn.	6040	---	636	---	2290
236.	Valvoline Oil Co.	Freedom, Penn.	986	207	---	---	---
237.	Vickers Petroleum	Ardmore, Okla.	5000	---	795	---	2610
238.	Vulcan Asphalt Ref.	Cordova, Ala.	477	---	---	---	---
239.	Warrior Asphalt Co.	Holt, Ala.	385	---	274	---	---
240.	West Coast Oil Co.	Bakersfield, Calif.	2540	---	636	---	318
241.	Westco Refining Co.	Cut Bank, Mon.	741	---	---	---	242
242.	Westland Oil Co.	Williston, N.D.	741	---	---	---	318
243.	Winston Refining	Fort Worth, Tex.	2390	---	---	---	405
244.	Wireback Oil Co.	Plymouth, Ill.	238	---	---	---	---
245.	Wolf's Head Oil Ref.	Reno, Penn.	334	80	---	---	---
246.	Yetter Oil Co.	Colmar, Ill.	159	---	---	---	---
247.	Young Refining Corp.	Douglasville, Ga.	398	---	207	---	---
	TOTAL		2262854	32531	107073	39628	1052858

Source: (1) "Annual Refining Survey," Oil & Gas J. 1 April 1974.

(2) National Petroleum News, Fact Book, Mid-May 1974, N.Y., McGraw-Hill, 1974.

Table D-1. HAZARDOUS CHEMICALS POTENTIALLY EMITTED FROM PROCESS MODULES

Chemical	Potential Emission Source Process Module Numbers
Maleic Acid	1,2,3,4,7,16,17,18,19,20,22,23,24,25,26,27,28,30
Benzoic Acid	1,2,30
Cresylic Acid	3,7,16,17,18,19,20,22,23,24,25,26,27,28,30
Acetic Acid	4,30
Formic Acid	4,30
Sulfuric Acid	27,30
Diethylamine	4,5,30
Methylethylamine	4,5,30
Aromatic Amines	18,19,26,30
Ammonia	3,5,7,16,17,18,19,20,22,23,24,25,26,27,30
Chlorides	1,2,30
Sulfates	27,30
Chromates	30
Ketones	1,2,3,7,16,17,18,19,20,22,23,24,25,26,27,30
Aldehydes	1,2,3,7,16,17,18,19,20,22,23,24,25,26,27,30,32
Formaldehyde	18,19,26
Acetaldehyde	18,19,26
Carbon Monoxide	5,9,10,12,13,16,17,18,19,20,22,24,25,26,27,32
Sulfur Oxides	5,10,13,16,17,18,19,20,22,24,25,26,27,32
Nitrogen Oxides	31,32
Pyridines	1,2,3,7,16,17,18,19,20,22,23,24,25,26,27,28,30
Pyrroles	1,2,3,7,16,17,18,19,20,22,23,24,25,26,27,28,30
Quinolines	28,30
Indoles	18,19,26,30
Furans	28,27,30
Benzene	1,2,3,7,10,13,14,16,17,18,19,20,21,22,23,24,25,26,27,28,29,30
Toluene	1,2,3,7,10,13,14,16,17,18,19,20,21,22,23,24,25,26,27,28,29,30
Xylene	1,2,3,7,10,13,14,16,17,18,19,20,21,22,23,24,25,26,27,28,29,30
Phenol	1,2,7,18,19,25,26,28,30
Dimethylphenol	1,2,27
Cresols	1,2,7,18,19,25,27,28,30
Xylenols	7,18,19,25,26,27,28,30
Thiophenols	26,30
Carbazoles	1,2,28,30
Anthracenes	1,2,18,19,26,28,30
Benzo(a)pyrene	18,19,26,28,32
Pyrene	18,19,26,30
Benzo(e)pyrene	18,19,26
Perylene	18,19,26,30
Benzo(ghi)perylene	18,19
Coronene	18,19,26
Phenanthrene	18,19,26
Fluoranthrene	18,19,26
Metalloporphrins	1,2,30
Nickel Carbonyl	10,16,17,20,22,24,27
Cobalt Carbonyl	10,16,17,20,22,24,27
Tetraethyl Lead	14,21
Sulfides	3,7,15,16,17,18,19,20,22,23,24,25,26,27,28,29,30
Sulfates	30
Sulfonates	3,7,16,17,18,19,20,22,23,24,25,26,27,28,29,30
Sulfones	30
Mercaptans	1,10,15,26,30
Thiophenes	1,2,3,7,16,17,18,19,20,22,23,25,25,26,27,28,30
Hydrogen Sulfide	1,3,5,7,10,13,15,16,17,18,19,20,22,23,24,25,26,27
Methylmercaptan	3,4,7,16,17,18,19,20,22,23,24,25,26,27
Carbon Dilsulfide	4,5,10,16,17,18,19,20,22,24,27
Carbonyl Sulfide	4,5,10,13,16,17,18,19,20,22,24,27
Thiosulfide	4
Dibenzothiophene	28
Alkyl Sulfide	28
Vanadium	1,2,10,16,17,18,19,20,22,24,25,26,27,28,30,32
Nickel	1,2,10,16,17,18,19,20,22,24,25,26,27,28,30,32
Lead	1,2,32
Zinc	1,2,18,19,25,26,28,30
Cobalt	10,16,17,20,22,24,27
Molybdenum	10,16,17,20,22,24,27
Copper	18,19,25,26,28,30,28
Strontium	28
Barium	28
Sulfur Particulates	5
Catalyst Fines	9,10,12,16,17,18,19,20,22,24,27
Coke Fines	10,16,17,20,22,24,25,26,27,32
Cyanides	4,5,18,19,26,30

Source: Cavanaugh, G., et al, Potentially Hazardous Emissions From the Extraction and Processing of Coal and Oil, EPA-650/2-75-038, Austin, Texas, Radian Corporation, and Columbus, Ohio, Battelle - Columbus Labs. (April 1975).

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